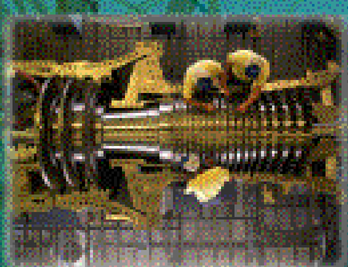
FRAMEWORK FOR EXPANSION OF THE WESTERN INTERCONNECTION TRANSMISSION SYSTEM, OCTOBER 2003



SSGwi

REPORT OF THE SEAMS STEERING GROUP-WESTERN INTERCONNECTION (SSG-WI)

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Appendices [1]

[1] Available electronically at the SSG-WI Website http://www.ssgwi.com

I Executive Summary

The Western Energy Crisis of 2001 raised a number of concerns regarding the impact of changes in the electricity industry on resource and transmission adequacy. The Western Governors' Association's (WGA) August 2001 report entitled, *Conceptual Plans for Electricity Transmission in the West*, recognized that the changing electrical industry regulatory structure has "uncoupled the historical linkages between new generation development and transmission construction" with no new industry structure to enable the construction of necessary transmission yet in place.

It is assumed that the three proposed western regional transmission organizations (RTOs) will eventually provide mechanisms to promote the construction of needed transmission infrastructure within their service areas. The SSG-WI Planning Work Group (PWG) was established to provide a forum to further the development of a robust West-wide interstate transmission system, an important pre-requisite for a seamless electricity market. Sub-regional transmission planning processes have also been established to facilitate transmission planning and expansion for specific geographic areas within the Western Interconnection (WI).

This report presents results from studies modeling transmission system congestion in the WI in 2008 and 2013 under different illustrative load and generation scenarios and assuming the dispatch of generation with the lowest operating costs first. The studies do not address transmission needed to maintain system reliability, to mitigate local market power problems, nor to optimize transmission/generation expansion.
These studies were performed to identify West-wide transmission needs for a range of possible futures and possible options to meet these needs.

The establishment of the SSG-WI PWG, the development of these studies and the initiation of Sub-regional Planning Groups represent implementation of several important next steps identified in the WGA report along the continuum toward construction of critical transmission infrastructure. (See Figure E-3)

Study Objectives

The studies were performed to meet the following three objectives:

1. To identify opportunities where the development of additional power transmission facilities could further facilitate competitive and efficient markets.

2. To provide policy-makers with information concerning transmission impacts of various energy policies being considered by State, Provincial and Federal entities.

3. To identify for generation developers major transmission additions that could be necessary to deliver a wide range of generation resources to load.

The 2008 study is considered the base case and only includes generation and transmission infrastructure reasonably certain to be in place by 2008. The 2008 study includes analyses under an average load forecast; low, average and high hydro conditions and a number of price ranges for natural gas. The 2008 study provides a benchmark for a 2013 load forecast by identifying congestion problems likely to occur if new resources and transmission are not developed.

The 2013 study evaluates the following three generation scenarios that are assumed to represent the bookends of possible generation infrastructure development in the 2013 timeframe.

- A gas-fired scenario that assumes 86 percent of new generation is fueled with natural gas and located near load centers;

- A coal scenario that assumes 66 percent of the new generation added between 2008 and 2013 is coal-fired; and

- A renewable energy scenario that assumes that 72 percent of new generation added between 2008 and 2013 is from renewable resources. The renewable energy scenario contains enough renewable energy generation to satisfy the Renewable Portfolio Standards that four states within the Western Interconnection have enacted.

As with the 2008 study, the 2013 study includes analyses under an average load forecast; low, average and high hydro conditions and a number of price ranges for natural gas.

Findings

A comparison of the average hydro and medium gas price condition in the 2008 study with a similar study of an unconstrained transmission system (see Figure V-I in the report) indicates that there is significant stranding of low-cost generation in Canada and in the Desert Southwest. Approximately 1300 miles of new 345 and 500 kV line would be required to completely alleviate this identified congestion, which could result in an annual savings in the production cost of generation, or Variable Operating and Maintenance (VOM) costs, totaling at least $110 million. One of the Sub-regional Planning Groups, the Southwest Transmission Expansion, or STEP Group, is already undertaking a more detailed investigation of upgrading existing lines and adding approximately 225 miles of new transmission line in the California-Arizona corridor. STEP estimates the benefit of this proposed project to be on the order of $60 million per year.

The study did not explicitly model the impact of measures to reduce demand. However, the study results do provide insights into the effect of load reduction on the need for transmission. In addition, the study shows that the need for new transmission is more sensitive to the price of natural gas than to hydro conditions, primarily because new generation added in the WI between 1998 and 2008 is predominantly natural gas-fired with over 25% of generation resources in 2008 fueled by natural gas.

Figure E-1 shows the results of the 2013 scenarios in terms of the costs, benefits, and simple payback periods associated with constructing new transmission and generation infrastructure compared to the benchmark case of no new infrastructure. As shown, a cursory evaluation of the capital costs of transmission and generation infrastructure was performed. The benefits in terms of production cost savings (VOM cost savings) are derived from the model results. Such costs as the cost of additional gas pipeline infrastructure or the costs associated with potential carbon emission regulation have not been evaluated. Benefits stemming from reliability improvements, improved market competition and increased ancillary services have also not been quantified. Although the study results should not be construed to mean that a particular scenario is cost-effective to construct because there is a need for more detailed analyses, the results do show simple payback periods of 6 to 13 years for the range of scenarios and sensitivities studied. Expected generation/transmission scenarios for the various WI sub-regions merit further evaluation, including the consideration of non-transmission alternatives such as demand reduction measures.

The new transmission infrastructure assumed to be in place by 2013 under each of the scenarios to facilitate the efficient use of generation to meet load is graphically shown in Figure E-2. The underlying system represents that which would be operational by 2008.

Accomplishments in Meeting Study Objectives

This report is an important step in meeting SSG-WI's transmission planning objectives and makes a valuable contribution to reestablishing the linkage between generation development and transmission construction.

STUDY OBJECTIVE 1: IDENTIFY TRANSMISSION INFRASTRUCTURE TO FACILITATE MARKETS:

In furtherance of SSG-WI's first objective, the studies identify:

- Areas in the Western Interconnection that are or may be congested in the near future (2008); and

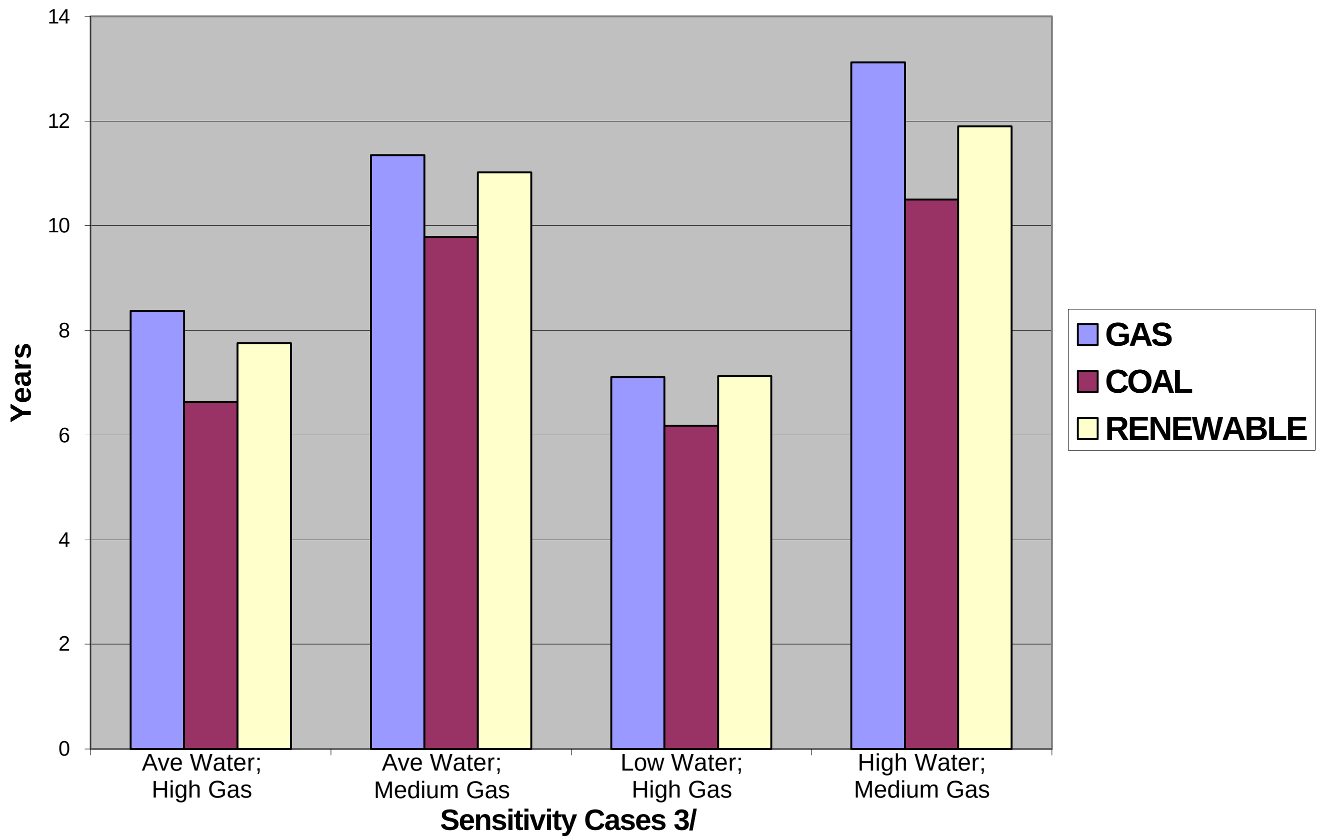
- Transmission facilities necessary to minimize production costs for three bookend generation scenarios.

Given the load and resource assumptions, these expansions of the transmission system are cost-effective. Further analysis is required before specific projects can be selected for construction.

Figure E-1: SSG-WI Study Results for 2013 Scenarios

	GAS	COAL	RENEWABLE
New Transmission (Miles)	1325	7600	3360
New Transmission Costs ($B)	2.64	16.74	6.71
New Generation (Installed GW)	57	57	67
New Generation Costs ($B)	17.44	30.51	36.76
Production Cost Savings for Sensitivity Cases ($B/yr) 1/			
• Average Water; High Gas	2.40	7.13	5.60
• Average Water; Medium Gas	1.77	4.83	3.94
• Low Water; High Gas	2.83	7.65	6.10
• High Water; Medium Gas	1.53	4.50	3.65

Simple Payback Periods for 2013 Scenarios 2/



1/ Production Cost Savings are evaluated compared with a base case of 2008 resources & transmission.
2/ Simple Payback is defined as sum of all capital costs divided by total annualized benefits.
3/ Other factors to consider before investment decisions are made include: fuel availability/resource diversity, construction lead time, transmission losses, environmental impacts/benefits, benefits to transmission/generation reliability, impacts on market competitions, ancillary services impacts/benefits, etc.

Solutions are being investigated in sub-regional planning forums. Sub-regional transmission assessments can define specific projects, identify the beneficiaries of such projects, and create the coalition of interests necessary for transmission infrastructure implementation. An iterative transmission planning process has been defined. The iterative process includes annual studies by the SSG-WI planning function and detailed investigations by the Sub-regional Planning Groups and the RTOs (once they are formed). All of these activities will be coordinated with state entities and local utilities performing integrated resource planning. (See Figure E-3, for a graphical depiction of this process.)

The SSG-WI planning effort is currently based on the voluntary support of interested stakeholders. Given the diverse makeup of the Western Interconnection, a large number of individual transmission owners and other interested parties are involved in this effort. This approach to planning transmission can be successful; however, implementing the projects that are planned can be difficult because of the many interests involved. The development of RTO's is expected to significantly mitigate this barrier, as the RTO's will have processes that not only facilitate planning, but also fund and construct new transmission.

STUDY OBJECTIVE 2: IMPACT OF ENERGY POLICY ON TRANSMISSION:

In furtherance of SSG-WI's second objective, the PWG:

- Finds that planning and implementation of transmission and generation infrastructure are difficult to coordinate because transmission infrastructure generally takes significantly longer to develop than generation infrastructure.

- Identifies transmission expansion that would relieve congestion for the coal, gas and renewable generation scenarios evaluated. (See Figure E-2)

- Finds that the transmission needed with the Renewable Scenario will support the amount of renewable energy generation necessary to satisfy the Renewable Portfolio Standards (RPS) that four states within the Western Interconnection have enacted. [2] Since the renewable generation levels in the Renewable Scenario exceed the RPS requirements, additional studies may be required to identify the minimum transmission required by the state RPS levels.

- Identifies transmission expansion that might lower electricity costs to consumers based on the preliminary economic analyses performed.

Energy policy-makers are currently faced with a number of issues and uncertainties that are tied directly or indirectly to transmission infrastructure development. National

[2] It is unclear whether the RPS requirements in the various states apply only to new, or also include existing renewable resources. The SSG-WI studies assumed that only new renewable resources count toward satisfying RPS requirements.

energy legislation may be forthcoming soon that addresses such issues as mandatory reliability standards, regional transmission organizations and electricity market designs.

In addition to transmission infrastructure adequacy, energy policy-makers are concerned with resource adequacy and diversity. A number of states within the Western Interconnection have enacted energy legislation that includes RPS, energy efficiency, environmental and other requirements. Following the Western Energy crisis of 2001, a number of states and regions are exploring whether to implement resource adequacy requirements. In addition, state regulators and load serving entities (LSEs) have renewed their efforts to perform integrated resource planning evaluations.

The scenario analyses performed by SSG-WI can help inform state policy-makers and regulators of the cost of transmission associated with alternative generation sources. This is valuable input into integrated resource planning activities, resource adequacy assessments and other evaluations being performed to address the issues identified above. These analyses are particularly valuable in providing insights into transmission additions that can support resource diversity and thus improve reliability. Conversely, the transmission infrastructure development process, graphically depicted in Figure E-3, depends on input from states, LSEs and developers. Transmission planning must be integrated with utility and independent developer plans in sub-regional studies in order to arrive at solutions for transmission and generation infrastructure that fully support the goals of energy policy-makers. Finally, detailed analyses of the impact of transmission additions on system reliability need to be conducted.

OBJECTIVE 3: IDENTIFY TRANSMISSION NEEDED TO DELIVER RESOURCES TO MARKET:

In furtherance of SSG-WI's third objective, the PWG finds:

- Gas-fired resources require significantly less new transmission since these resources are generally located near load centers.

- Significant transmission additions are required to transmit remote coal and renewable resources identified in the study to load centers. The results of this initial screening are promising in terms of identifying potentially cost-effective additions for the assumed resources scenarios.

- The transmission facilities identified for all of the scenarios may also provide reliability benefits for the WI power system.

- Certain transmission facilities were found to be needed in all three resource scenarios. Since the need for these facilities is less sensitive to resource assumptions, the sub-regional planning groups may want to focus first on these facilities as possible economic additions to the system.

As part of this initial study effort, a WI production-costing database has been developed. SSG-WI intends that this database be made available for use by the Sub-regional Planning Groups and others interested in joint database development. A beneficial and effective relationship has been established between the SSG-WI PWG and the western Sub-regional Planning Groups. These consensus-based efforts should be supported and encouraged to continue. These efforts will be expanded to include RTOs, once these are formed.

Next Steps

The following steps are proposed to advance transmission development in the Western Interconnection:

- Federal, State and local policy-makers need to address and resolve institutional and financial barriers[3] to the construction of needed transmission infrastructure. These issues include transmission line siting, cost allocation and cost recovery. These issues need to be resolved to encourage investment in transmission infrastructure and demand efficiency measures at loads.

- The Sub-regional Planning Groups should perform more in-depth transmission expansion planning studies for those facilities within their sub-regions identified in this SSG-WI study, based upon expected generation additions and load forecasts (e.g. coordinated with utility integrated resource plans that are approved by state public utility commissions);

- SSG-WI should perform annual reviews of the utilization of the existing transmission system, potential future needs, and expansion issues, including those issues associated with differences in transmission and generation construction lead times. SSG-WI should coordinate its future study program with the Sub-regional Planning Groups. SSG-WI should initiate long-term planning efforts and identify appropriate cost and benefit indicators for future analysis, including fuel price volatility, fuel availability, environmental impact, ancillary service impacts, construction lead times, losses, reliability improvement and impacts on market competition.

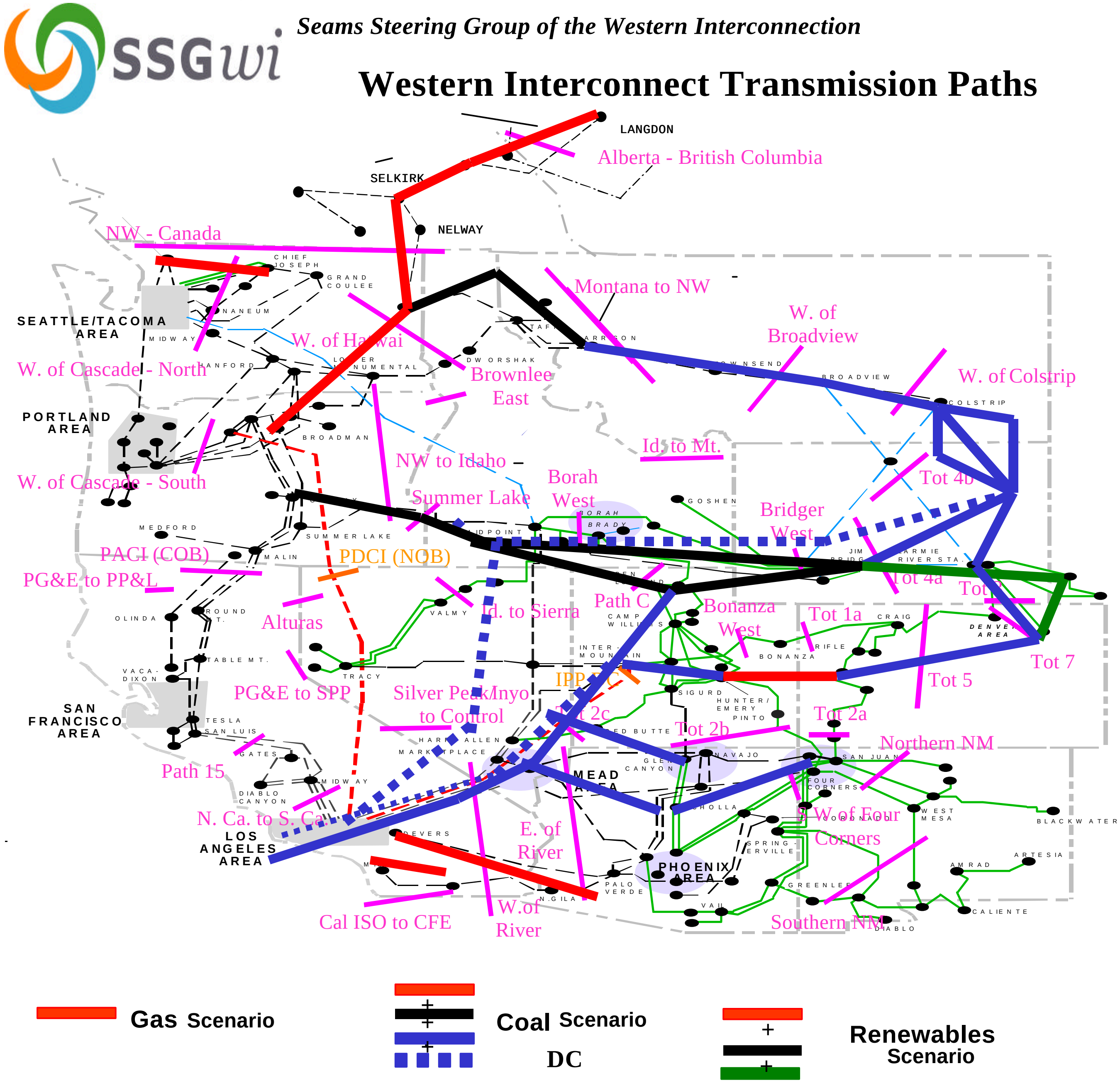
- Development and funding of model and economic methodology improvements and forums to improve transmission planning methodologies need to be investigated and pursued. For example, study methodologies (particularly benefit calculations) need to be fine-tuned and improvements are needed to more accurately model hydro and wind resources as well as market behavior. A process for continuing the development of a common, public and consistent database needs to be finalized.

[3] Barriers exist that impede not only the construction of transmission lines, but also that impede demand-side technologies, including strategically sited generation, to delay or obviate the need for new transmission lines.

- Federal, state and local policy-makers will need to decide whether to finance and permit transmission expansions to facilitate generation resource diversity, including meeting renewable energy goals in RPS's.

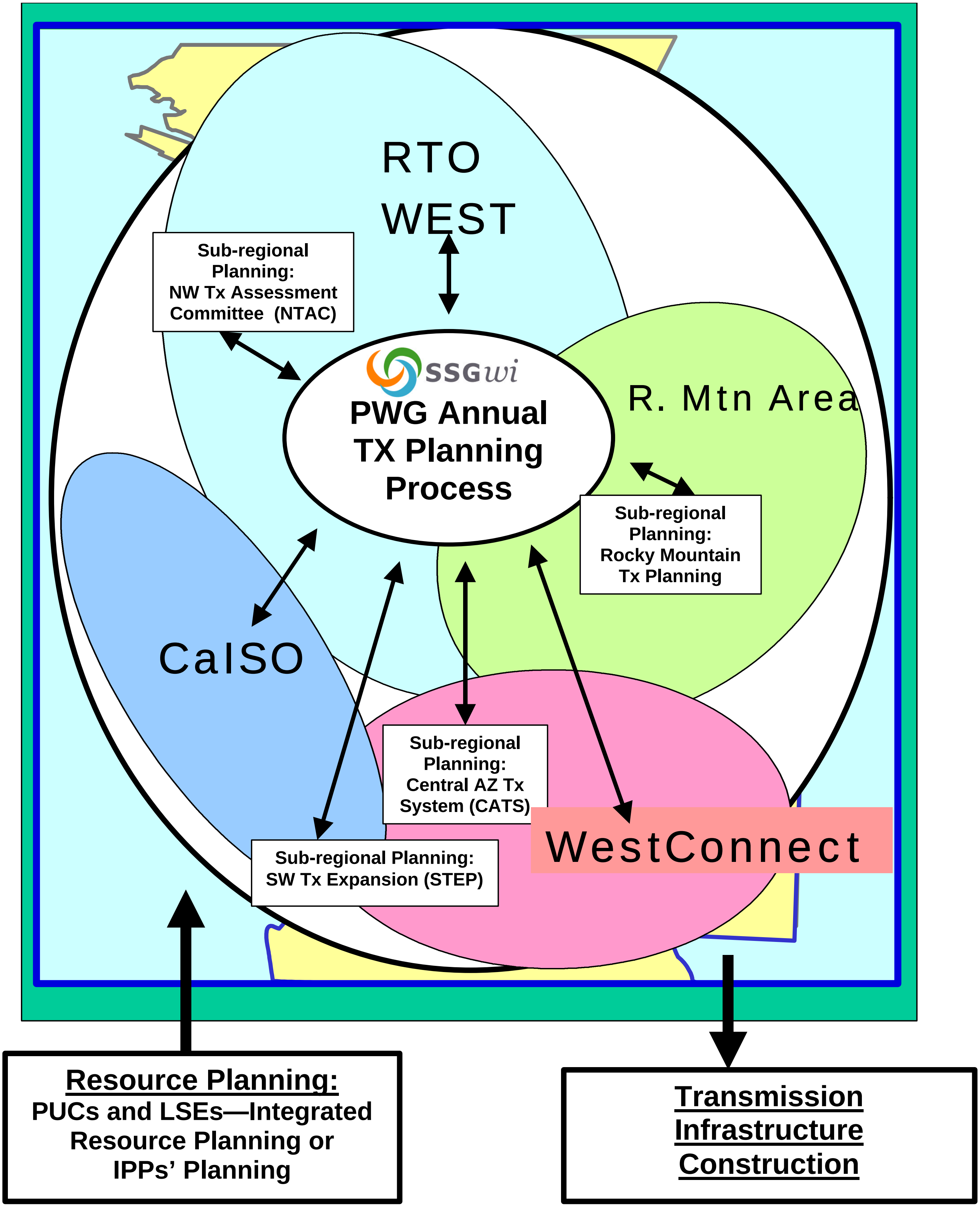
- As Sub-regional Planning Groups perform detailed studies to identify beneficiaries and as incentive pricing and cost recovery issues are addressed and resolved, coalitions of interested parties will need to come together to plan, finance and construct critical transmission infrastructure. The development of RTOs will likely be critical to making mechanisms available to fund and construct new transmission infrastructure.

Figure E-2 Western Interconnection Transmission Additions



1 Alberta-BC
2 Alberta – Saskatchewan
3 Northwest – Canada
4 West of Cascades – North
5 West of Cascades – South
6 West of Hatwai
7 Blank
8 Montana to Northwest
9 West of Broadview
10 West of Colstrip
11 West of Crossover
12-13 Blank
14 Idaho to Northwest
15 Midway – Los Banos
16 Idaho – Sierra
17 Borah West
18 Idaho – Montana
19 Bridger West
20 Path C
21 Arizona to Calif
23 Four Corners 345/500
24 PG&E – SPP
25 PacifiCorp/PG&E 115 Intercon.
26 Northern – Southern Calif
27 Intermountain Power Project
28 Intermountain – Mona 345 kv
29 Intermountain – Gonder 230 kv
30 TOT 1A
31 TOT 2A
32 Pavant/Intermtn Gonder
33 Bonanza West
34 see paths 78 & 79
35 TOT 2C
36 TOT3
37 TOT 4A
38 TOT 4B
39 TOT 5
40 TOT 7
41 Sylmar to SCE
42 IID – SCE
43 North of San Onofre
44 South of San Onofre
45 SDG&E Comision Fed. de Elect.
46 West of Colorado River (WOR)
47 Southern New Mexico (NM1)
48 Northern New Mexico (NM2)
49 East of the Colrado River
50 Cholla – Pinnacle Peak
51 Southern Navajo
52 Silver Peak – Control 55 kv
53 Billings – Yellowtail
54 Coronado West
55 Brownlee East
56-57 Blank
58 Eldorado – Mead 230 kv Lines
59 WALC Blythe – SCE Blythe

Figure E-3: Transmission Infrastructure Development Process



II. Introduction

Motivation for West-wide Transmission Expansion Planning

The Western Interconnection (WI) covers 1.8 million square miles in all or parts of 14 U.S. states, two Canadian provinces and Northwest Mexico with almost 116,000 circuit miles of transmission. There are 33 control areas, two functioning Independent System Operators and three proposed RTOs. More than 70 million people currently rely on the transmission system to meet their electricity needs. At growth rates averaging 2.2% annually, electricity demand will increase from about 781,000 GWh in 2002 to about 948,000 GWh by 2013. Increasing demand will require increased investment in some combination of generation (central station and distributed), transmission, energy-efficiency and demand response infrastructure.

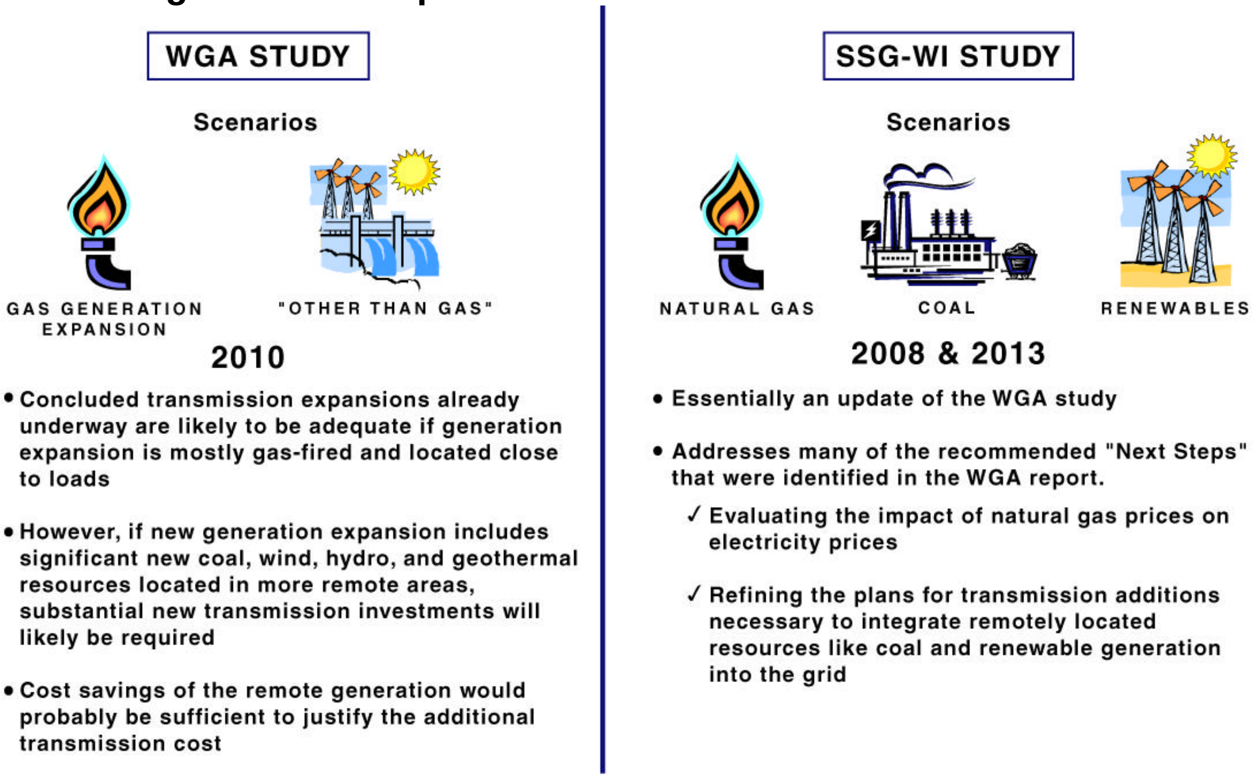
In the past, vertically-integrated utilities that owned both generation and the transmission system planned and built generation and transmission to meet their needs. Once a project was announced, regional coordinated planning was undertaken. Since the Federal Energy Regulatory Commission's (FERC) open transmission access Order 888 in 1996, the close linkage between generation and transmission planning has eroded. The Western electricity crisis of 2001 prompted the region's political leaders to ask whether adequate generation and transmission was being planned and built to meet the region's needs. Since 2001, the state's public utility commissions have increased their focus on utilities' Integrated Resource Plans (IRPs). California and the Northwest are in the process of evaluating what constitutes resource adequacy for their sub-regions.

The crisis led to an expedited effort to pro-actively estimate future transmission needs in the WI, which was documented in the August 2001 WGA report, *Conceptual Plans for Electricity Transmission in the West*. The WGA evaluation presented two book-end generation expansion scenarios for 2010 and developed conceptual transmission expansion plans for both scenarios. These included a gas generation expansion scenario and an "other than gas" scenario with large amounts of new coal-fired and renewable generation. Figure II-1 and Appendix E summarize the conclusions of the WGA report and shows that the SSG-WI study represents a next step toward the goal of eventually developing critical transmission infrastructure to serve West-wide needs. (See Figure E-3)

In a February 2002 report to the Western Governors, the region's stakeholders concluded that a pro-active transmission planning process is a necessary (but not sufficient) requisite for financing needed transmission. Subsequently, Western governors urged the development of an ongoing pro-active, interconnection-wide transmission planning effort. In its RTO orders, FERC also requested that the Western RTOs develop a pro-active, seamless interconnection-wide planning process. The establishment of SSG-WI's PWG transmission planning function addresses FERC's request as well as the concerns of the Western governors.

This effort is being performed in coordination with the Western Electricity Coordinating Council (WECC) to establish a close working relationship between the reliability functions of WECC and the expansion planning functions of SSG-WI.

Figure II-1: Comparison of WGA and SSG-WI Studies



<u>Context and Purpose of SSG-WI Study</u>

This report documents the initial work of the SSG-WI PWG, which draws its members from a broad-based group of public and private sector stakeholders of the three proposed western RTOs and other interested parties within the WI. The PWG was formed in 2002 to establish a collaborative west-wide forum with the goal of facilitating seamless transmission planning across the WI. A brief description of the SSG-WI planning process, and how it works with other planning activities in the WI, is provided in the Section VII of this report.

The work of the PWG is focused on identifying transmission projects that enhance wholesale power markets through the mitigation of uneconomic congestion. It is clear that the development of a robust competitive wholesale generation market is dependant on the availability of a robust transmission system. While the need for developing the transmission system to enhance wholesale power markets has existed long before industry restructuring, industry restructuring has made this more challenging and has led to an increase in participants in the power markets with an increasing focus on the development of a robust transmission system.

To determine the need for additional transmission facilities, the PWG first had to estimate the amount and location of future load growth and evaluate potential generation additions. Instead of developing one expected resource scenario, the PWG decided to develop generation scenarios that represent the book-ends of potential generation additions by generation type, to evaluate the changing transmission needs based on different scenarios of generation additions. After developing these load and generation assumptions, detailed mathematical models were used to simulate the hourly operation of the WI over a year's time. The output of these models identified congested transmission interfaces and allowed the estimation of economic savings to both producers and consumers achievable by reducing or eliminating this congestion. A comparison of these savings to the cost of transmission additions needed to mitigate congestion will facilitate decisions of whether or not to pursue detailed studies/construction of transmission project(s).

Two years were selected for study—2008 and 2013. These timeframes provide a near-term and mid-term perspective on the use of the transmission grid. For the mid-term case (2013), a wide variation in potential resource plans was studied to aid policy makers in developing energy policy for the west. The three alternate resource plans presented in this report focused on gas, coal, and/or renewable generation additions.

The completion of these studies is intended to meet the following three needs:

- To identify opportunities to further facilitate competitive and efficient markets through the development of additional power transmission facilities. The results of this study will be used in various planning processes to help facilitate reinforcements to the transmission system where that is determined to be economically beneficial.
- To provide policy-makers with information concerning transmission impacts of various energy policies being considered by State and Federal entities. For example, this study helps to identify the major bulk transmission facilities that would likely be necessary to integrate large quantities of wind generation into the WI.
- To identify to generation developers the major transmission additions that could be necessary to deliver specific generation resources to load. Generation developers have stated to SSG-WI that this information is critical to their ability to successfully develop these new resources.

In addition to the production cost studies, the PWG has completed an analysis of actual transmission path utilization data from 1998-2002. This information was used to provide insights into congestion concerns that exist today and to help benchmark the production cost studies. An overview of this work is provided in Section III of this report. The results of the SSG-WI PWG studies are described in Sections V and VI of this report. Section VII discusses the SSG-WI Planning Function and Section VIII summarizes the overall findings, accomplishments and next steps of this evaluation.

III. Historical Path Flow Study

SSG-WI's initial step in evaluating the western transmission system was to explore historical utilization of the major transmission paths in the Western Interconnection using data on actual flows from 1998 through 2002. The analysis of actual historical power flow data provides an indication of how marketers and load serving entities have utilized the transmission system to market energy and serve load. This information is also useful in the analysis and identification of potential future areas of congestion and for verifying model representation for power flow and production costing analysis. The information can also be used to understand anomalies where transmission scheduling is constrained despite actual flows being less than path transfer capabilities. However, it cannot be used to conclude whether there was significant congestion (defined as the inability to obtain transmission capacity when needed) on a path. In addition, it cannot be concluded from this historical analysis that it is either necessary or economical to take any corrective actions for the loading levels reported. SSG-WI's February 2003 *Western Interconnection Transmission Path Flow Study* can be found at SSG-WI's website: http://www.ssgwi.com/documents/.

The analysis was performed for 33 transmission paths, representing all the major transmission paths in the western interconnection. Figure E-2 in the Executive Summary provides a schematic diagram of all of the west-wide transmissions paths and cross-walks the path numbers with path descriptors and locations.

The analysis utilized real time hourly power flow and operating transfer capability (OTC) data submitted by path operators and archived in the Western Electricity Coordinating Council's (WECC) EHV Data Pool database. Most data in the EHV Data Pool database is complete. In some cases, the real-time path OTC was not reported and assumptions were made based upon published path transfer capabilities. These assumptions are noted in SSG-WI's February 2003 report.

To facilitate comparison among the paths, a utilization indicator was calculated. This indicator is calculated as the percentage of time the path exceeds 75% of its OTC over the season reported. The 75% level was chosen as an indication of a path that may be considered heavily utilized. This figure was developed for purposes of the February 2003 report and has no basis in terms of an accepted industry standard or practice. The magnitude of the indicator is not necessarily an indication that there is congestion, or an inability to meet the needs of transmission users, on the path. In the WI, paths are designed to be loaded to 100% of their OTC and withstand a credible N-1 outage without violating reliability standards.

A second loading indicator presented in the report, is the peak loading during the season. This indicator does not include a time factor as does the 75% indicator.

The following observations may be drawn from the analysis:

1. The following paths had at least one season over the study period, in which the seasonal loading exceeded 75% of OTC 50% of the time or greater: (These may be considered the more heavily utilized paths relative to their operating transfer capability. This by itself is not an indication that these are the most commercially congested paths. These are also not the most heavily loaded paths in terms of the magnitude of MW loading)

    Path 19 – Bridger West
    Path 27 – IPP DC Line
    Path 50 – Cholla – Pinnacle Peak
    Path 22 – Southwest of 4 Corners
    Path 47 – Southern New Mexico
    Path 30 – TOT 1A (Colorado to Utah)
    Path 36 – TOT 3 (Wyoming to Colorado)

2. Paths with the highest loadings relative to their transfer capabilities are primarily located in the Rocky Mountain and Desert Southwest regions (Wyoming, Colorado, Arizona and New Mexico).

3. The two most heavily loaded paths, West of Bridger and the Intermountain Power Project DC Line, are transmission paths with high load factors dedicated to the integration of generating plants in Wyoming (Jim Bridger) and Utah (Intermountain Power Project).

4. For use in future analysis, improvements should be made in the data reporting procedures for data to be included in the WECC EHV Data Pool database. One area that should be reviewed is the calculation and reporting of OTC limits.

While the analysis focused primarily on congested lines, it also indicates that some paths are not heavily loaded during many hours. More efficient utilization of the existing transmission system could make it possible to add additional generation--especially intermittent renewable generation which does not require transmission capacity to be available in all hours--without having to construct as many new lines.

Because the study looked at actual power flows and not at scheduled transfers or contractual delivery commitments, it is not possible to estimate the number of megawatt hours of underutilized transfer capability that might be available throughout the region. Doing so will require further study. But it is clear that under current practice, many lines in the region are shown to have no Available Transfer Capacity (ATC) while in reality these lines are constrained only several hours a year.

Taking advantage of underutilized transmission assets requires only closer regional cooperation and a revised tariff structure. This could provide potentially significant benefits by reducing the costs of adding new generation and deferring the need for new transmission in certain areas of the WECC.

Figure III-1 summarize the path “peak loading.” The graph presented in Figure III-2 shows the percentage of time that flows were at least equal to 75 percent of the path’s OTC. The bars are for the season (winter, spring, summer) of greatest path utilization during the 1998-2002 study period.

Figure III-1: Peak Seasonal Path Loading - Per Unit of Path OTC
Winter, Summer and Spring Seasons
Winter 98-99 thru Spring 2002

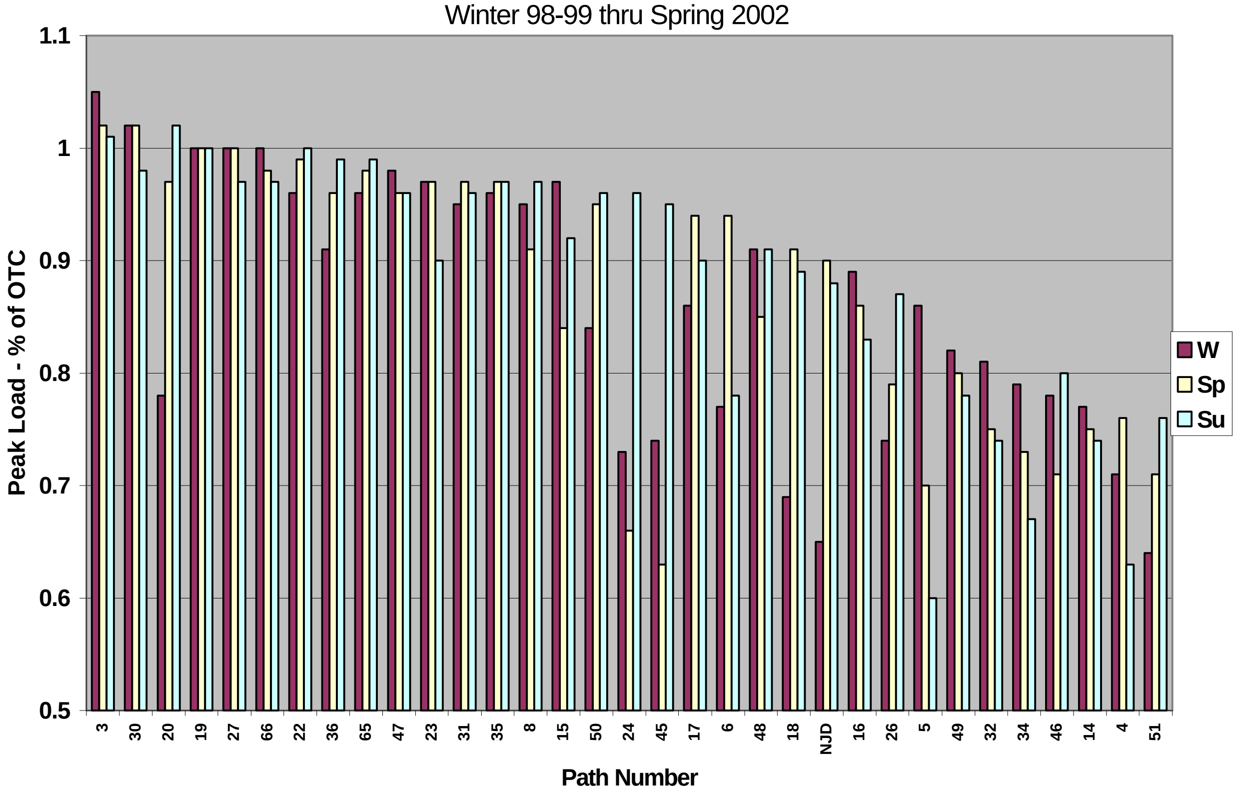
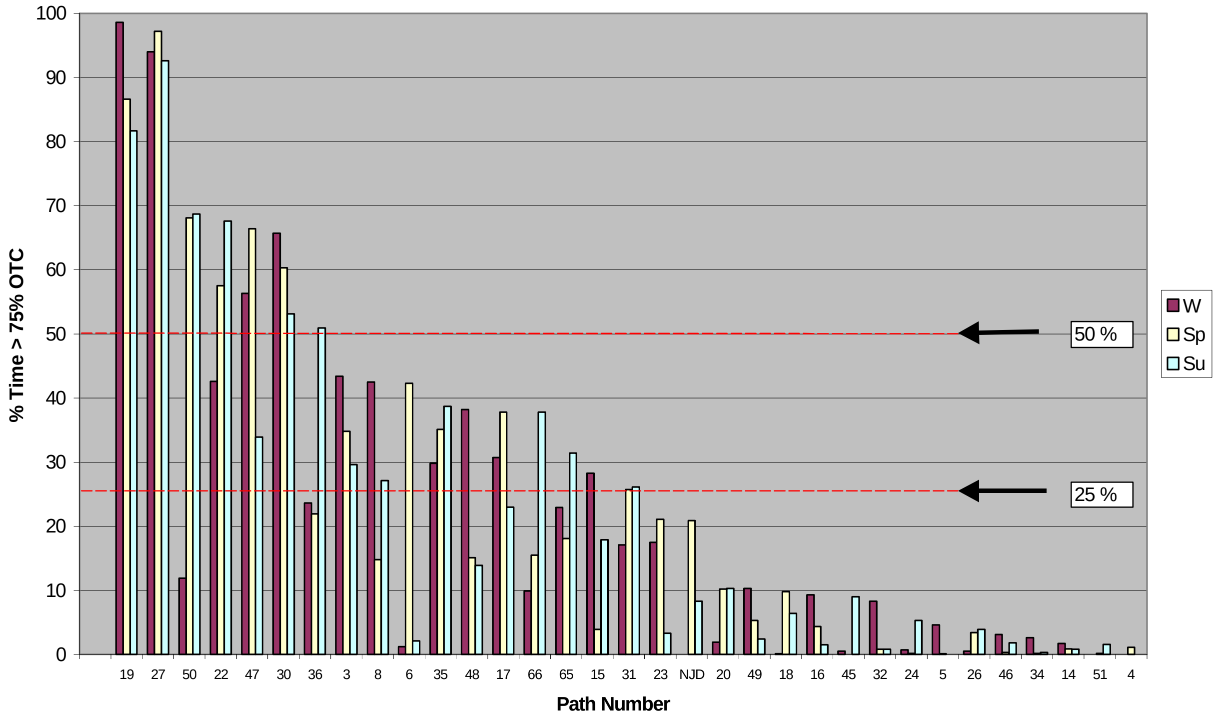


Figure III -2: Path Loading - % of Time > 75% of Path OTC for a Season
Maximum Seasonal Loadings for each Path
Winter 98-99 thru Spring 2002



IV. Transmission Study Methodology

It is important to understand what this congestion analysis is and what it is not. The analysis:

- Simulates transmission congestion in 2008 using conservative assumptions about generation and transmission additions likely to be in service by that time;
- Simulates transmission congestion in 2013 under three different generation scenarios;
- Assumes the dispatch of generation with the lowest operating costs first as a simplified approach to simulating the market;
- Quantifies benefits in terms of savings in the production costs of generation; it shows the shifts of benefits between consumers and generators through changes in locational marginal prices thus allowing for the identification of potential transmission project beneficiaries;
- Provides a source of information for –
  - Market participants, thereby encouraging collaboration in defining and planning specific transmission projects;
  - Sub-regional transmission planning;
  - State/Federal/provincial policy makers on transmission needs and costs associated with different future generation scenarios and by inference different energy policies.
- Represents the next step along the path of proactive, interconnection-wide transmission planning begun with the release of the August 2001 WGA Report.
- Assumes the transmission grid may be used to its full physical capacity without institutional constraints; assumes a single, west-wide control area, a single tariff, and flow-based rather than contract path-based scheduling of transmission.

The analysis does <u>not</u>:

- Constitute a transmission plan ready for implementation in the Western Interconnection;
- Represent a least-cost resource plan;
- Consider (except in the most cursory fashion) the capital cost of generation options, or demand-side management options, nor does it provide a cost-benefit analysis of constructing new transmission;
- Evaluate the risks associated with future fuel prices or environmental regulation;
- Optimize interconnection-wide transmission expansion;
- Consider the value of transmission expansion to mitigate the exercise of market power; or quantify the specific benefits of individual project additions.
- Consider generation related infrastructure and associated costs like the expansion of natural gas infrastructure

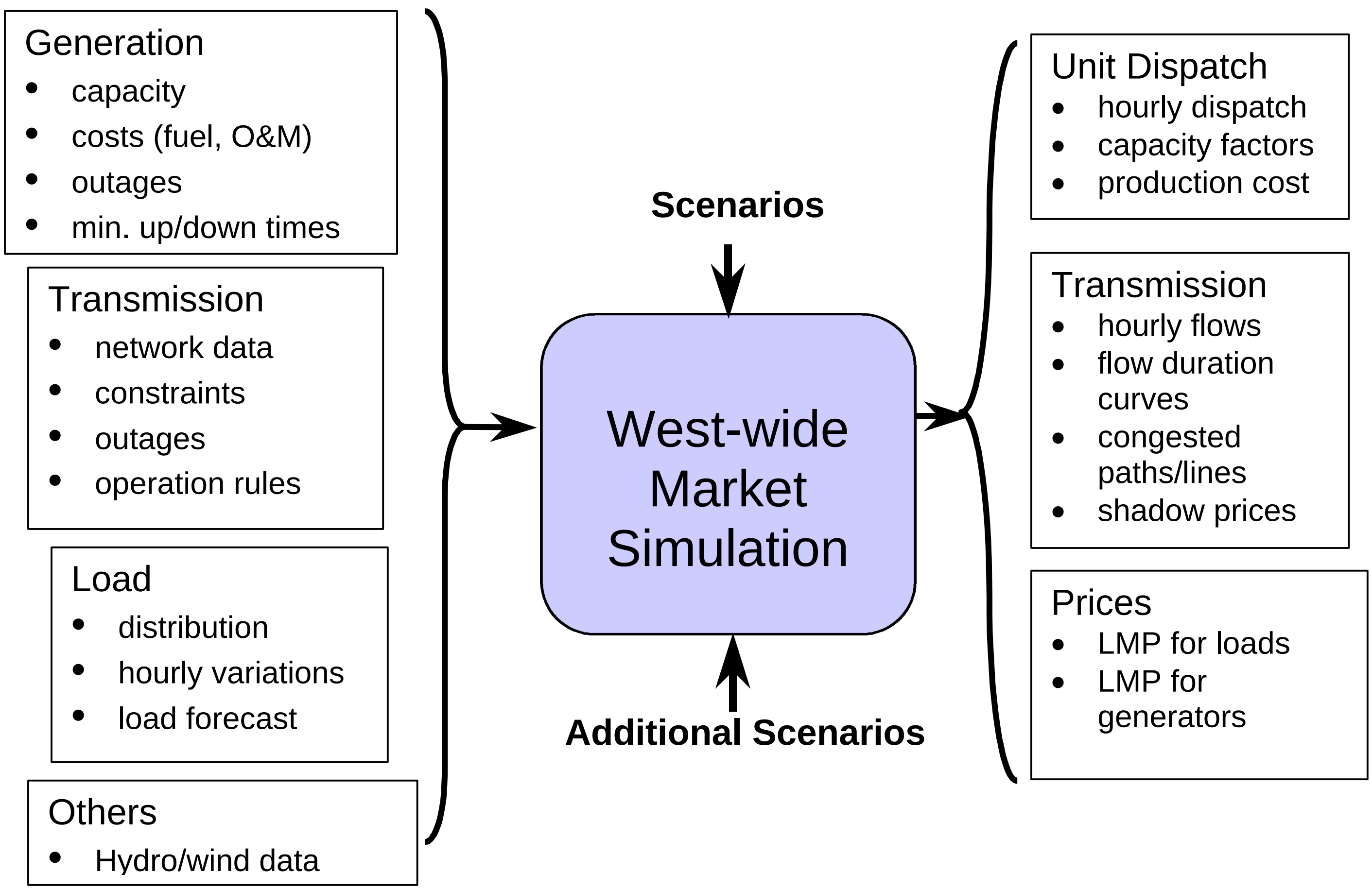
These study results should be used as a screening tool to identify potential transmission infrastructure projects for more in-depth analyses. Efforts are being made to make as much input data and modeling results as possible publicly available so that other parties can perform additional analyses or verify the conclusions in this report. The analysis is limited by the quality of data available, the sophistication of modeling tools, the assumptions regarding economic dispatch, and the ability to predict loads and renewable resource output, particularly of the Northwest hydro system. These caveats would apply to any simulation of the system, and on balance, the SSG-WI Planning Work Group believes this methodology to present a reasonable, useful assessment of possible future system parameters.

Modeling Approach

Appendix A provides a detailed description of the modeling methodology; inputs; approach to modeling hydro, wind and distributive generation/energy efficiency; modeling limitations; and validation of results. A brief description of the modeling approach is:

- The starting point for the analysis is the WECC 2008 LSP1-SA approved base case.
- The hourly demand at each node of the transmission system is determined by imposing/fitting the set of load distribution factors from the WECC power flow case onto the forecasted load shapes for 2008 and 2013.
- The ABB MarketSimulator model performs an economic dispatch of thermal power plants to simulate the low-cost approach to meeting load. Hydro, wind, and solar resources are hard-wired (see Appendix A for description of hydro, wind and solar models).
- The physical limitations of the transmission system are modeled, which tends to strand some less expensive generation at times. The costs to generate and the costs to meet load are shown in terms of Locational Marginal Prices (LMPs). Transmission shadow prices (see definitions in Appendix G) are the reduction in costs from a 1 MW increase in the capacity of that line. See Figure IV-1 for a graphic depiction of the modeling approach.

Figure IV-1 Quantification of Benefits using Production Simulation Analysis



Description of Model Assumptions for Generation

Simulation of Hydroelectric Generation for Median, High and Low Water Conditions

In order to test the sensitivity of the study economics to the level of hydroelectric generation, studies were run for three sets of water conditions—medium, high and low.

For Canada and the Northwest, modified hydrology associated with the following historical years was used to represent the three water conditions: 1930 for low water with an annual Columbia River runoff of 93.7 million acre-feet (MAF), 1953 for average water with an annual Columbia River runoff of 133.3 MAF, and 1948 for high water with an annual Columbia River runoff of 170.3 MAF. The modified hydrology associated with each of these three water conditions was run through water-power operation studies that modeled the non-power constraints of the reservoir systems and used any flexibility in the reservoirs to shape the generation to meet load. These studies produced monthly estimates of generation as well as maximum and minimum plant capacities.

The California Energy Commission has twenty years of hourly generation records for the hydroelectric plants in California. The limited period of record is not conducive to selecting single years to represent the three water conditions. Instead, the four driest years were averaged to represent the low water condition. All of the years were averaged to represent the average water condition. The four wettest years were averaged to represent the high water condition.

Given the large storage to runoff ratio for hydroelectric power plants in the Desert Southwest, it was assumed that in any one year, hydroelectric generation could be regulated as needed. Therefore, the average hydroelectric generation associated with these plants is deemed representative of all three water conditions. This simplifying assumption was made due to a lack of a historical record of hydroelectric generation by year and because the magnitude of hydroelectric generation is small compared to that in the remaining Western Interconnection.

Evaluation of median, high and low gas prices

In modeling transmission congestion in 2008 and 2013, SSG-WI used three alternative gas price assumptions: a low U.S. natural gas well-head price of $2.15/mcf in 2008 and $2.69/mcf in 2013; a medium well-head price forecast of $3.23 in 2008 and $3.77 in 2013; and a high well-head price forecast $4.84 in 2008 and $5.30 in 2013. All numbers are in 2003 dollars.

These gas price assumptions were selected to cover a wide range of future prices. Because the most recent price forecast done in 2003 is significantly higher than the forecasts done in 2002, SSG-WI has focused its analysis on its medium and high gas price scenarios.

Figure IV-2 shows how the SSG-WI gas price assumptions compare with recent wellhead gas price forecasts by the California Energy Commission, the Northwest Power Planning Council, the Energy Information Administration's *Annual Energy Outlook 2003*, GII (formerly DRIWEFA), and EEA.

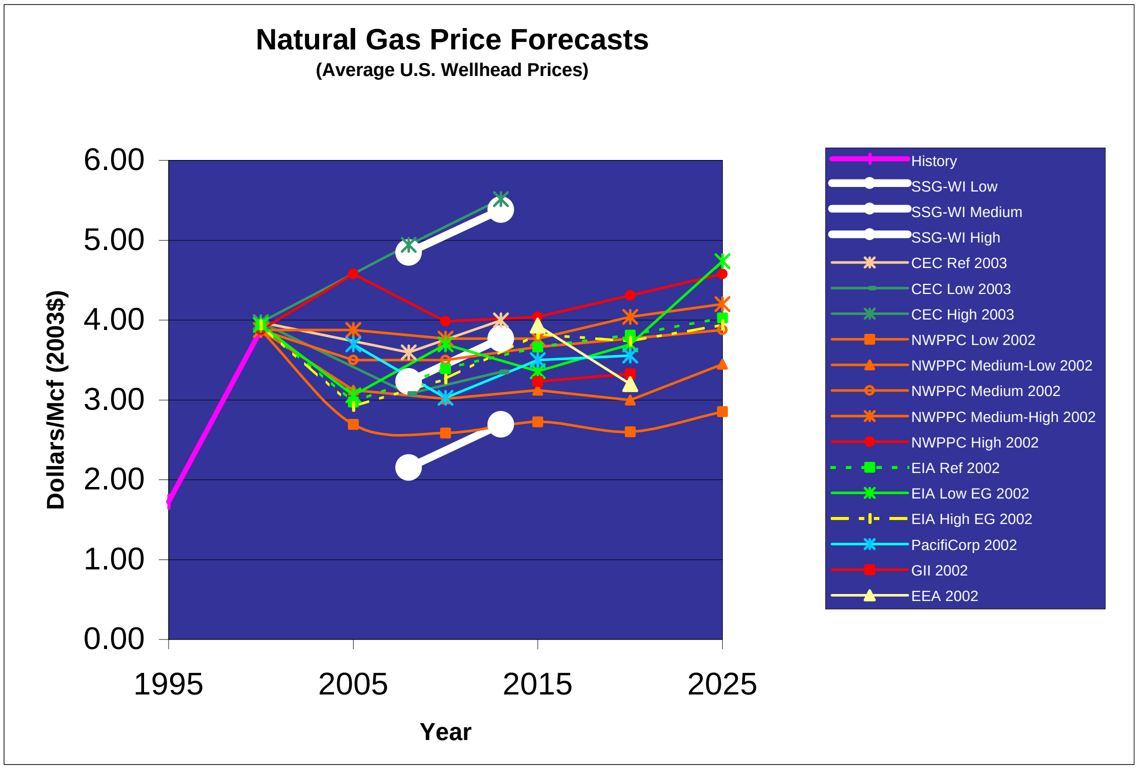


Figure IV-2

Basis differentials and gas transportation costs are added to the assumed U.S. wellhead prices. The basis differentials and transportation adders are from the Northwest Power Planning Council's "Fuel Price Forecasts for the Fifth Power Plan," September 2002. Appendix B shows the assumed delivered cost of gas for each of the modeling regions.

OVERVIEW OF GENERATION SCENARIOS

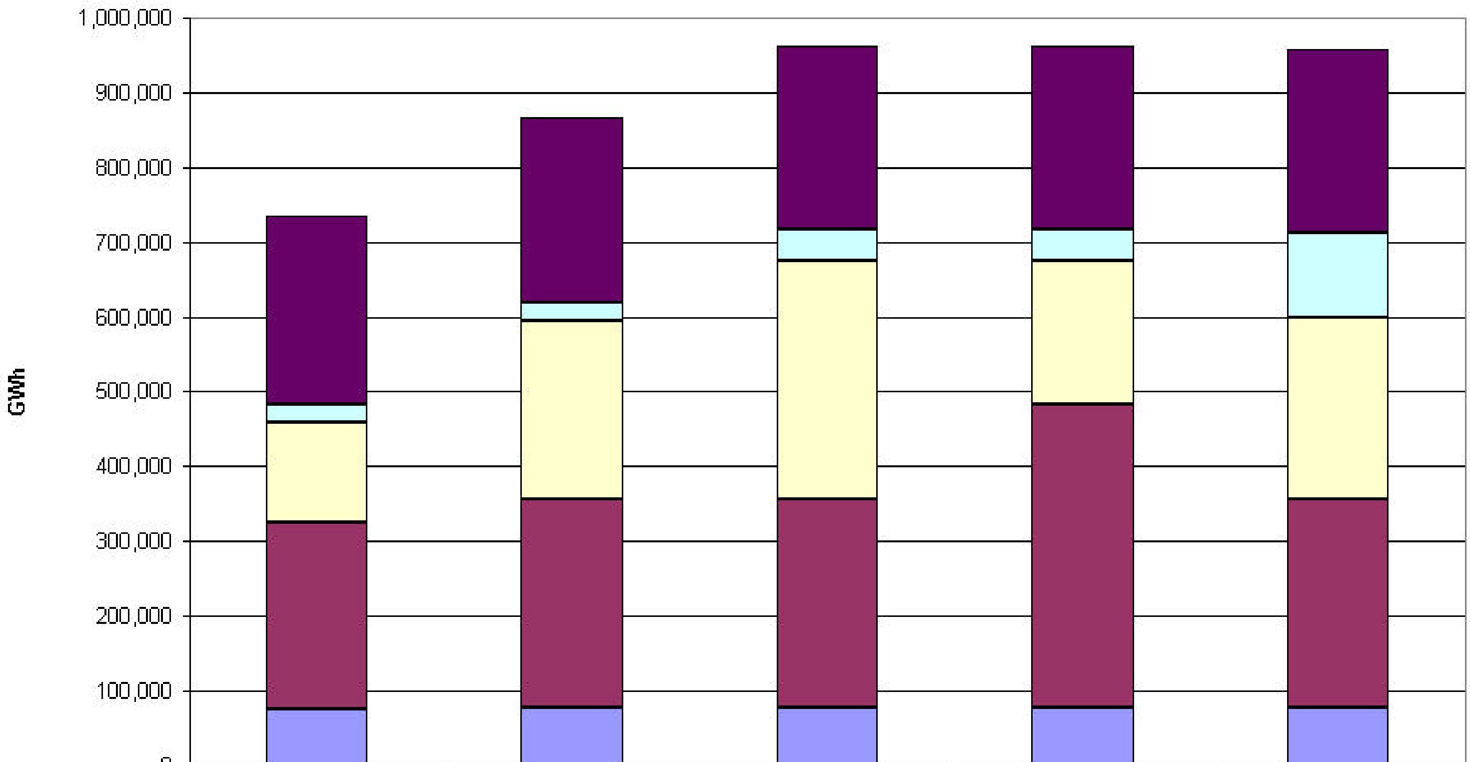
The goal of the generation scenarios is to demonstrate the implications of new power plant choices on the transmission system. The 2008 scenario includes only new power plants that are likely to be online by mid-2004. These plants are primarily natural gas fired. The level of congestion in the 2008 scenario provides a benchmark for the three 2013 scenarios and helps identify imminent congestion problems.

From 2008 to 2013, three very different scenarios were modeled: one with mostly new natural gas plants, one with a mix of renewable and natural gas plants and one with mostly coal-fired plants. These scenarios are intended to represent the bookends of possible resource mixes with a combination of the three scenarios representing the most likely resource mix in 2013. For all four scenarios only announced retirements are removed from the generation mix.

Each 2013 scenario adds enough new power plants to more than adequately meet utility forecasts of load growth and reserve requirements. SSG-WI has not tried to develop one scenario that minimizes the combined cost of new plants, transmission additions and the operating costs for all plants. Uncertainties about future load growth, fuel costs and environmental regulations make it impossible to create a single least-cost plan. Detailed descriptions of the types and locations of the generation additions for the 2008 and 2013 scenarios are shown in Appendix B.

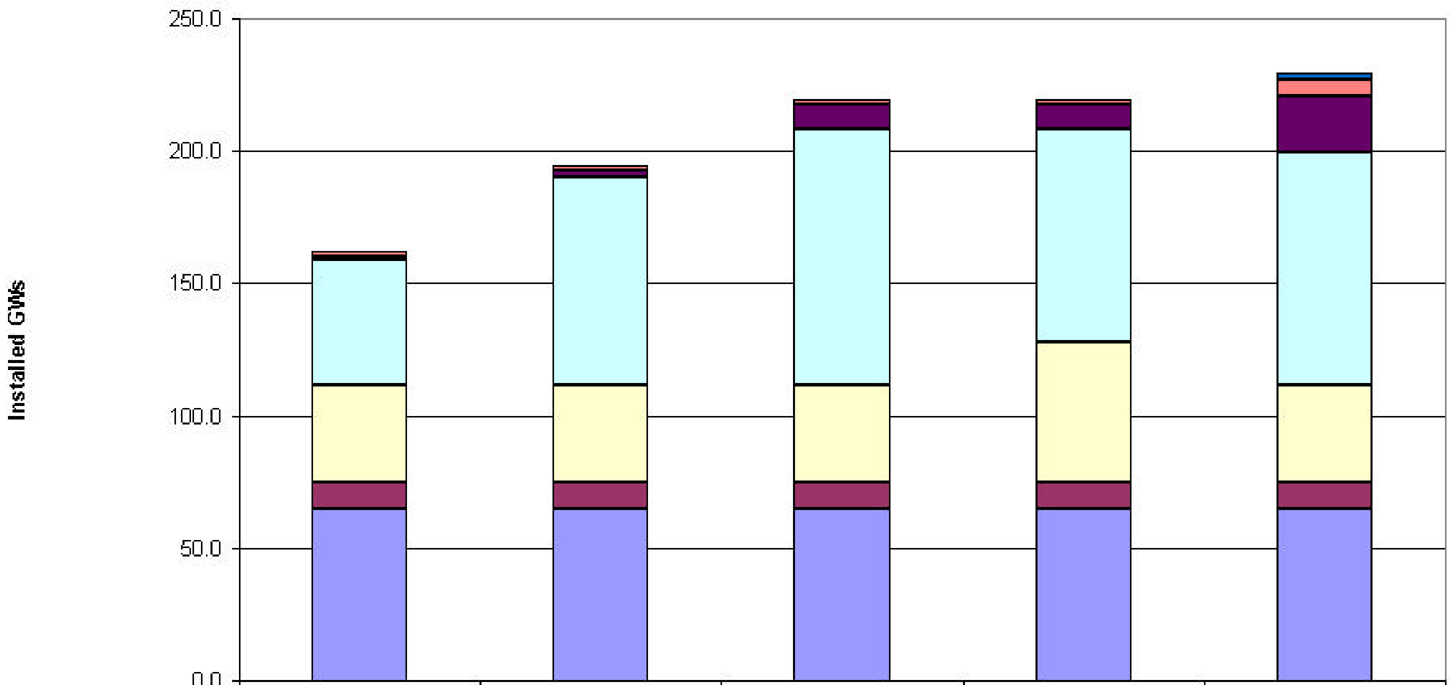
Figure IV-3 indicates the generation mix for the Western Interconnection for 1998, the 2008 scenario and the three 2013 scenarios under average water conditions.
Figure IV-4 depicts the installed capacity by generation type (in GW) for the same years and scenarios.

Figure IV-3: Generation Mix in GWH/year – Western Interconnection



	1998 Expected MWh	2008 AW MG	Gas 2013 NC	Coal 2013	Renewable 2013
Hydro	251,658	246,090	246,090	246,090	246,090
Renewables	23,889	24,244	42,395	42,395	112,984
Gas	132,593	237,925	317,224	191,767	243,675
Coal	249,972	279,813	279,839	405,367	277,929
Other	75,905	77,634	77,359	77,359	77,359

Figure IV-4: Installed Capacity by Generation Type - Western Interconnection



	2000	2008	2013 Gas	2013 Coal	2013 Renewable
Solar	0.0	0.0	0.0	0.0	2.5
Geo & Biomass *	2.1	2.1	2.1	2.1	5.8
Wind *	1.2	2.8	9.4	9.4	21.4
Gas	47.4	78.3	96.5	80.2	87.8
Coal	36.6	36.9	36.9	53.2	36.9
Nuclear &Other	10.2	10.2	10.2	10.2	10.2
Hydro	64.6	64.6	64.6	64.6	64.6

Distributed Generation, Energy Efficiency and Demand Response (Non-wires Alternatives)

Although specific separate cases were not developed to examine the impact of accelerated energy efficiency and demand response investments or expanded use of distributed generation, the modeling information provides insight on the impacts such developments would have on transmission needs. For example, an indication of the impact of reduced demand in 2013 can be garnered from examining the model results using 2008 load levels. If load growth between 2003 and 2013 occurred at the rate of 1 percent per year instead of the assumed 2 percent per year, demand in 2013 could be met with the transmission assumed to be in place in 2008. An indication of the impact of distributed generation on transmission needs can be garnered from the natural gas scenario where new generation is located close to load centers.

Some argue that delay in making large investments in transmission without jeopardizing the integrity of the grid is prudent since such a strategy allows more of an unknown future to unfold. For example, if new technologies, such as economical fuel cells, develop, congestion on the transmission system could decrease significantly. As potential transmission additions move from the conceptual level in this report to sub-regional planning and project-specific analyses, the quality and specificity of demand reduction and distributed generation options will increase. This should, in turn, allow for well-informed, balanced judgments to be made on the timing and location of new transmission investment. For a more complete discussion of non-wire alternatives, refer to Appendix B.

RESERVE CAPACITY MARGIN VS. RESOURCE ADEQUACY

In order to be consistent with the WGA study, a 25% reserve margin was assumed to be a proxy for resource adequacy. However, it should be noted that there is no relationship between this assumption and the ongoing efforts in certain sub-regions of the WI to establish resource adequacy metrics and possibly standards Especially in the Northwest where hydro is a predominant resource, a reserve capacity margin has little meaning in terms of ensuring resource adequacy given the energy limited nature of the resource.

The capacity associated with both thermal and hydro resources was assumed to be nameplate capacity. Please refer to Appendix B for a discussion of wind capacity factor versus the capacity credit. This report assumes a standard capacity credit of 20% for each wind plant for the reasons discussed in Appendix B.

Description of Model Assumptions for Transmission

2008 STUDY

The objective of transmission representation in the 2008 case was to reflect the transmission infrastructure that will exist based upon facilities currently committed for operation in 2008. To accomplish this objective, transmission facility representation for the 2008 case was taken from the WECC 2008 LSP1-SA approved base case, dated March 2003. As an approved base case, this information had been previously coordinated by WECC among its membership through the WECC base case development and approval process. Path ratings were taken from the latest WECC Path Rating Catalog dated February 2003. Nomograms were modeled in the study to reflect known facility interaction constraints.

Changes were made to the 2008 LSP1-SA BASE CASE for SSG-WI PWG Studies to reflect the current thinking of the transmission facilities likely to be in place by 2008. Following are descriptions of projects that are currently under construction, or in the final planning phases that are assumed to be in place by 2008: (Projects that are added to the 2008 studies would increase path capability beyond the present WECC Path Rating Catalog.)

NORTHWEST

- A new Schultz-Wautoma 500 kV line was added along with a Wautoma substation on the existing Hanford – John Day 500 kV and Hanford – Ostrander 500 kV lines. This project increases North of John Day capability (Path 73).

- The Coulee-Bell 500-kV line was added along with series compensation in the Bell – Taft 500 kV line and the Dworshak – Taft 500 kV line plus 230-kV line additions to Avista's system to improve West of Hatwai capability (Path 6).

- Series compensation has been added at Schultz substation on the Echo Lake - Kangley – Schultz 500 kV and the Raver – Schultz #1 500 kV lines to increase Cross Cascades North Path (Path 4).

- The Kangley – Echo Lake 500 kV line was added extending the Schultz – Raver #2 line into Echo Lake. A new SnoKing 500/230 kV transformer was also added. These additions will improve the usability of the Northwest to Canada Path (Path 3).

- Added the Falcon-Gonder 345 kV project that increases the capability of Path 32.

CALIFORNIA

- Path 15 reinforcements – The primary addition here is a new Los Banos Gates 500 kV line. This will increase the south to north rating on Path 15 from 3900 MW to 5400 MW.

- Miguel Area reinforcements – These additions increase the ability to transfer power from the desert southwest into San Diego. They include a second Miguel 500/230 kV transformer, a second Miguel-Mission 230 kV line, and an increase in the thermal rating of series compensation in the Imperial Valley-Miguel 500 kV line. The new capability from the Imperial-Valley 500 kV bus to the Miguel 230 kV bus will be 2240 MVA. The limit north of Miguel into San Diego will increase to 2000 MW.

DESERT SOUTHWEST

- Added Palo Verde-TS5 Line and associated Projects.

ROCKY MOUNTAIN

- Added the Walsenburg-Gladstone 230 kV tie between Colorado and New Mexico which may increase the capacity of Path 31 and 48.

2013 STUDY

The objective of the transmission representation in the 2013 case was to identify areas of transmission congestion for the various generation scenarios and areas where transmission would need to be added to effectively utilize the resource additions. Transmission was only added on the bulk transmission system. Transmission costs for the various scenarios would need to recognize the cost of feeder transmission not represented in these studies. Additional transmission would be required to integrate the new generation into the bulk system; however, this was not represented in the study.

First, a run was made with no transmission added over those facilities included in the 2008 case. Path load duration curves for the initial 2013 studies showed many paths with flows at peak capacity for a significant amount of the time, indicating that new transmission was needed.

The first iteration with transmission added was done by noting the transmission paths that were operating at rated capacity for a significant amount of time, and adding capacity to the system so that these paths would operate below their capacity limit at least 75% of the time. This criteria was set as an approximation to initially determine the facilities that could likely be added economically. Blocks of capacity additions of 1000 to 1500 MW were assumed to require 500 kV transmission; 500 to 1000 MW blocks were assumed to require 345 kV transmission additions, if appropriate. Planning judgment was used in all cases as to the best area to add transmission reinforcements and the amount of transmission required. Sufficient transmission was added so that reliability criteria were expected to be met, however no power flow or stability studies were run to verify reliability performance. Reliability performance would need to be verified. In many cases, the transmission added was not on the congested path, rather on another path that would be more effective in alleviating the congestion.

The initial transmission addition iteration relieved approximately 90 % of path congestion. It was decided to make a second iteration to attempt to economically relieve some of the additional 10% of congestion. The first step of the second iteration involved having the model develop a list of the shadow prices for the more heavily utilized paths for each of the three scenarios. Paths with shadow prices exceeding approximately $20,000 per MW were reviewed and a judgment was made whether capacity additions might economically further reduce congestion. Changes included additional transmission, increased series capacitor ratings, relocation of the new DC line terminals, phase shifters additions and moving new renewable generation locations. In some cases nothing was done because it was felt the added cost might outweigh the added benefit. Studies were then rerun with the second iteration of transmission.

The following are projects that were added to the 2013 studies in response to the congestion that resulted from the production cost studies of the three generation scenarios.

GAS SCENARIO (needed for all three scenarios)

- A new Langdon-Cranbrook-Selkirk-Bell 500 kV line (420 miles) was added to increase the capability of the Alberta-BC and BC-NW paths (Paths 1 and 3).

- The Harquahala-Devers 500-kV line (200 miles) and the Hassyamp-North Gila-Imperial Valley-Miguel 500 kV line (280 miles) were added to increase the West of River and East of River path capability (Path 46 and 49).

- A new Sycamore-Ramona-Imperial Valley 500 kV line (120 miles) was added to increase the capability into San Diego (Path 42).

- The Chief Joe-Monroe 500 kV line (122 miles) was added to improve the capability of the Cross Cascades North (Path 4).

- A Grand Junction-Emery 345-kV line (180 miles) was added to improve the capability several paths from Colorado and Wyoming into Utah (Path 30, 33 and others).

RENEWABLE SCENARIO (incremental transmission needed for this scenario)

- A new Garrison-Hot Springs-Bell-Ashe 500 kV line (425 miles) was added to increase the capability of the Montana-NW and West of Hatwai paths (Paths 8 and 6).

- A new Midpoint-Melba-Grizzly 500 kV line (370 miles) was added to increase the capability of the Idaho-NW path (Path 14).

- A new Midpoint-Bridger-Ben Lomond-Midpoint 500 kV loop (790 miles) was added to increase the capability of the Path C, West of Borah and West of Bridger (Paths 17, 19 and 20).

- A new Green Valley-Stegall-Bridger 500 kV line (450 miles) was added to increase the capability through Wyoming (new path).

COAL SCENARIO (incremental transmission needed for this scenario)

- A new Colstrip-Broadview-Garrison-Hot Springs-Bell-Ashe 500 kV line (760 miles) was added to increase the capability of the Montana-NW and West of Hatwai paths (Paths 8 and 6).

- A new Midpoint-Melba-Grizzly 500 kV line (370 miles) was added to increase the capability of the Idaho-NW path (Path 14).

- A Crystal-Mira Loma 500-kV line (260 miles) was added to increase the capability of the West of River path (Path 46).

- Three new Colstrip-Wyodak 500-kV lines (130 miles each) were added to increase the capability of the TOT4B Path (Path 38).

- A new Wyodak-Bridger 500-kV line (290 miles) was added to increase the capability of the TOT4A path (Path 37).

- A new Bridger-Ben Lomond-Midpoint 500 kV loop (470 miles) was added to increase the capability of the Path C, West of Borah and West of Bridger (Paths 17, 19 and 20).

- A Wyodak-Laramie River 500-kV line (135 miles) was added to increase the capability of the TOT3 path (Path 36).

- An Emery-Mona-Crystal 500-kV line (520 miles) was added to increase the capability of the TOT2A, TOT2B1, TOT2B2 and TOT2C paths (Paths 31, 35, 78 and 79).

- A Melba-Caldwell/Locust/Boise Bench 230-kV lines (100 miles) was added to increase the capability of the path Idaho to NW Path (Path 14).

- A Shiprock-Moenkopi-Marketplace 500-kV line (542 miles) was added to increase the capability from Four Corners to Las Vegas (Paths 22, 23 and others).

- A Wyodak-Los Angeles 500-kV DC line (1375 miles) was added to increase the capability to move power from Wyoming to Los Angeles, crossing several paths.

Description of Model Assumptions for Load

The load forecast was taken from the WECC SUMMARY OF ESTIMATED LOADS AND RESOURCES, January 2002. This report gives summer peak, winter peak, and annual energy load forecasts by regions through 2011. The 2013 loads were simply extrapolated from the 2001-2011 trend. The model required monthly peak and energy amounts by powerflow area. As most regions cover several areas, the area detail was built from public sources (e.g. FERC 714 forms, or filed least-cost plans) with missing information approximated. The constructed area load data was then sent out to the SSG-WI participants for comment and improvement.

The model runs hourly, so the monthly peak and energy load data were spread to hours by use of historic load shapes (again FERC 714 data). The area load data was then spatially spread to the network by the distribution on area load found in the powerflow model.

Long-term Model Improvements

The SSG-WI Planning WG has formed a Model Improvement Group whose task is to identify modeling improvements that will improve the methodology and consequently the accuracy of future SSG-WI studies. A discussion of the areas identified is included in Appendix C.

The following modeling improvement areas are discussed in Appendix C:

1. Hydro
2. Wind Generation Characteristics
3. Modeling Uncertainty
4. New Resource Acquisitions
5. Bus Bar Loads
6. Game Theory and Market Behavior
7. Marginal Losses
8. Transmission and Generation Rights
9. Dimensionality

V. 2008 Simulation Results

The model was run for five cases in 2008:

1. High Water, Medium ($3.23/mmbtu average wellhead price) gas
2. Average Water, Medium Gas
3. Average Water, High ($4.85/mmbtu average wellhead price) gas
4. Low Water, High Gas
5. An Average Water, Medium Gas run with all transmission constraints turned off.

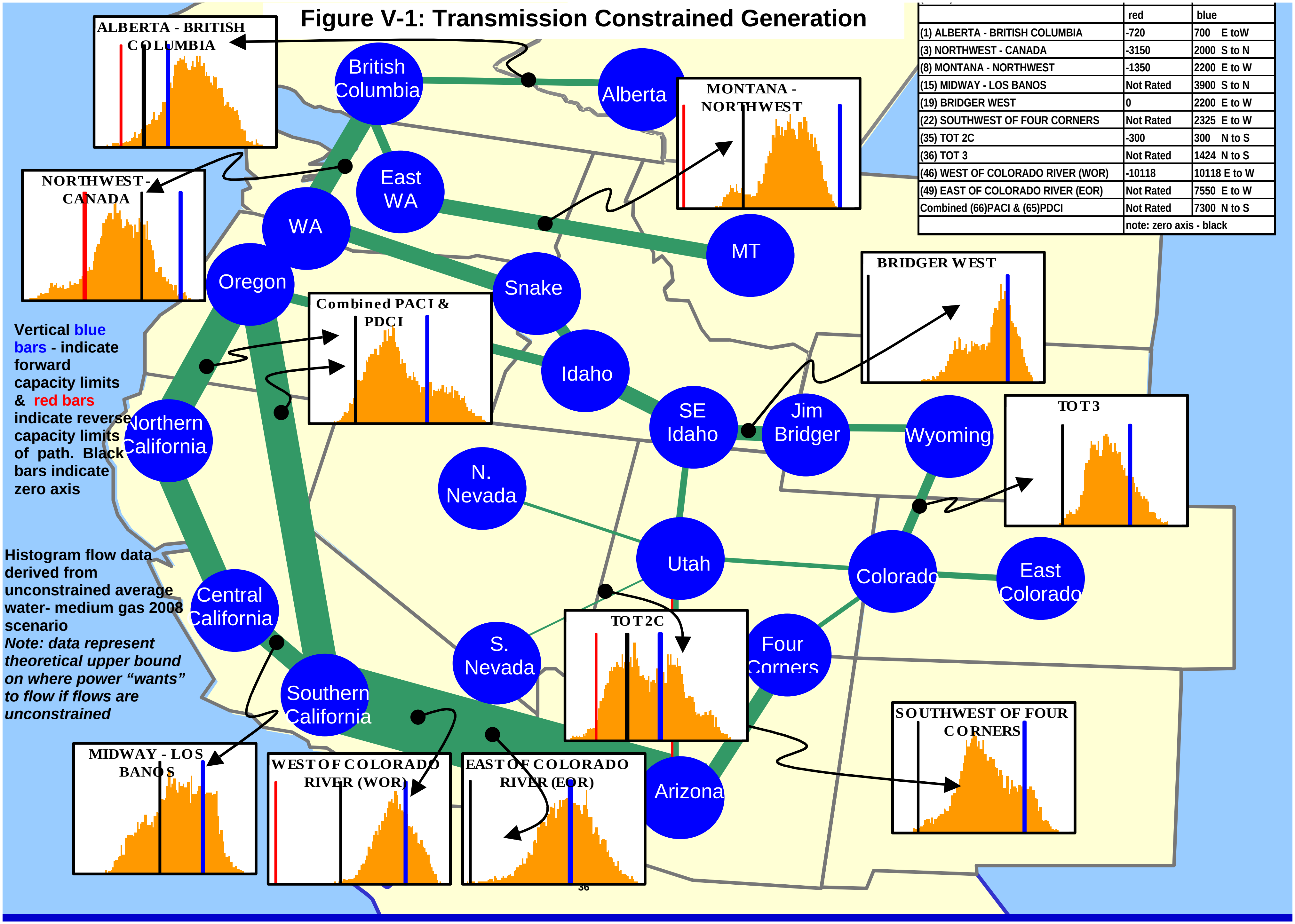
A comparison of Case 3 (with the transmission assumptions described in Section IV in place) with Case 5 assuming unconstrained transmission serves to identify the areas of transmission constraint. Figure V-1 on the next page is a graphic depiction of this comparison. Power flow outside the vertical red and blue bars indicates that more power than available capacity wants to flow along a particular path thus identifying an area of congestion.

The results of the production cost module of the model for the first four cases are displayed in Figure V-2. The production costs, also referred to as Variable Operating and Maintenance Costs (fuel and non-fuel) (VOM) were estimated to be in the range of $10.5-16.4 Billion for the year 2008 in real 2003 dollars.

The production cost model calculates these estimates based on approximations of plant costs. There was no attempt to model bidding behavior that would arise from either a competitive market, or market power. Even in the equilibrium, some bids would be quite different than running costs, as peaking and cycling units would need to cover their fixed costs, or become bankrupt. Bankrupt participants would not be part of an equilibrium solution.

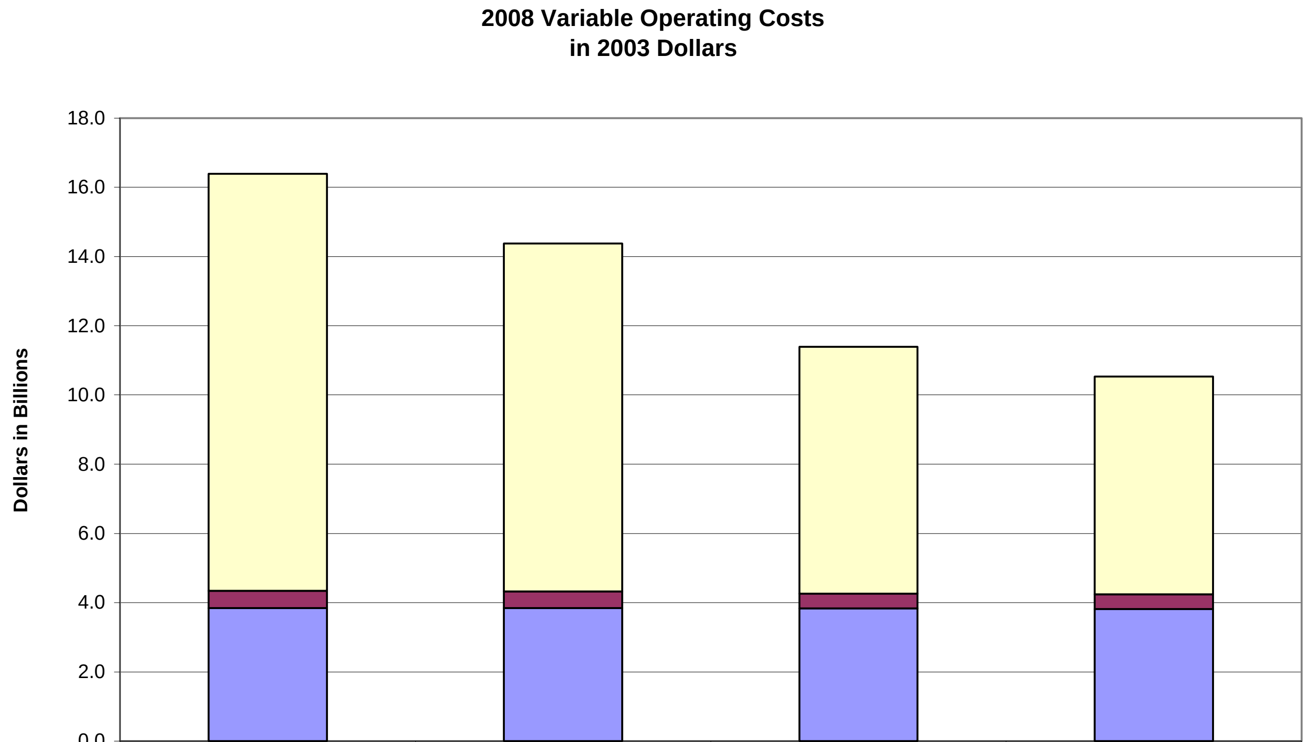
The total VOM costs are more sensitive to the gas price assumptions than to the hydro assumptions. The VOM costs move about $1 billion when moving from average water to high water, and about $2 billion when moving from average water to low water. The modeled VOM costs move $3 billion when moving from medium to high gas prices (wellhead average price moving from $3.23/mmbto to $4.85/mmbtu).

Figure V-1: Transmission Constrained Generation



	red	blue
(1) ALBERTA - BRITISH COLUMBIA	-720	700 E toW
(3) NORTHWEST - CANADA	-3150	2000 S to N
(8) MONTANA - NORTHWEST	-1350	2200 E to W
(15) MIDWAY - LOS BANOS	Not Rated	3900 S to N
(19) BRIDGER WEST	0	2200 E to W
(22) SOUTHWEST OF FOUR CORNERS	Not Rated	2325 E to W
(35) TOT 2C	-300	300 N to S
(36) TOT 3	Not Rated	1424 N to S
(46) WEST OF COLORADO RIVER (WOR)	-10118	10118 E to W
(49) EAST OF COLORADO RIVER (EOR)	Not Rated	7550 E to W
Combined (66)PACI & (65)PDCI	Not Rated	7300 N to S
	note: zero axis - black	

Figure V-2

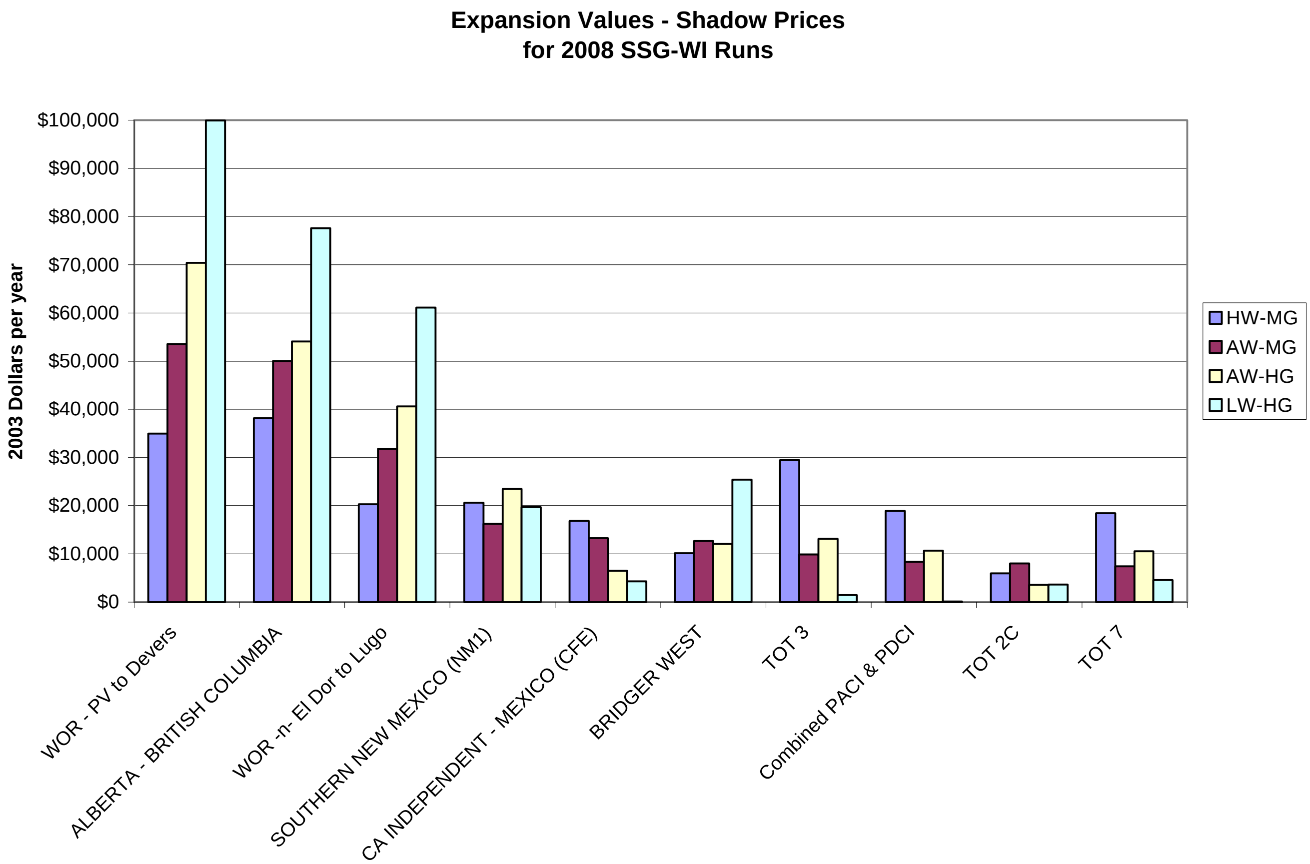


	LW-HG	AW-HG	AW-MG	HW-MG
Gas	12.1	10.1	7.1	6.3
Other	0.5	0.5	0.4	0.4
Coal	3.8	3.8	3.8	3.8

LW = Low Water   AW = Average Water   HW = High Water
MG = Median Gas Price   HG = High Gas Price

Congestion in the 2008 case is somewhat relieved by modifications that are well under way and assumed to be completed prior to 2008. These include a third 500 kV line on Path 15, a second 500 kV line on West of Hatwai, a number of modifications to West of Colorado River paths, among other transmission upgrades. Even with these modifications, the model shows significant congestion in the 2008 case. Measured against VOM cost changes alone (ignoring bidding behavior, potential market power or any reliability improvement benefits), the savings in VOM costs from eliminating transmission congestion is estimated at about $110 million per year for 2008. Figure V-3 below shows the models estimates of the paths with the highest annual shadow prices. A number of these paths are reinforced, directly or indirectly, in the 2013 cases.

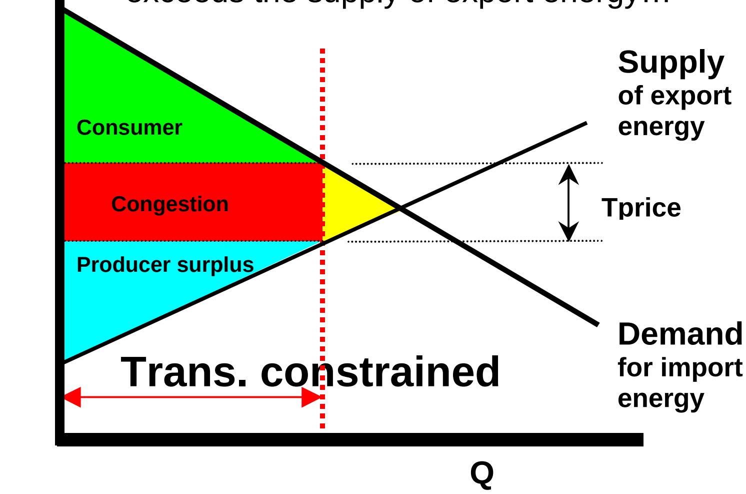
Figure V-3



SIDEBAR 1 on the next page discusses that the results of the model not only identify benefits in terms of VOM cost savings, but also in terms of benefits accruing to the various parties—consumers and producers of generation as well as owners of transmission. Even though the shift in these benefits does not represent a benefit to society as a whole, this shift serves to identify the beneficiaries of proposed transmission projects and thus helps bring potential participants together for possible collaborative transmission infrastructure projects. Because there is currently no freely traded transmission market, transmission owners/users may not feel price impacts on new transmission projects immediately. Rather future markets or tariffs will capture these changes.

SIDEBAR 1: A conceptual representation of the 2008 study results

In any given hour and for any given path, the spot market price or opportunity cost of transmission capacity, i.e., Tprice, is positive whenever the demand for import energy exceeds the supply of export energy…



… And, if we assume there are no legacy rights holders, then all transactions using the path pay Tprice.

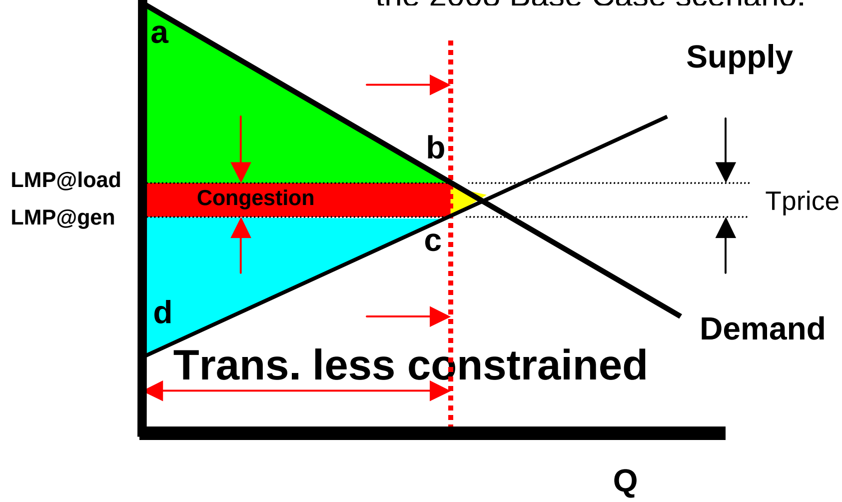
Hence, the maximum amount of congestion revenue can be represented by the red rectangular area as shown in the diagram to the right.

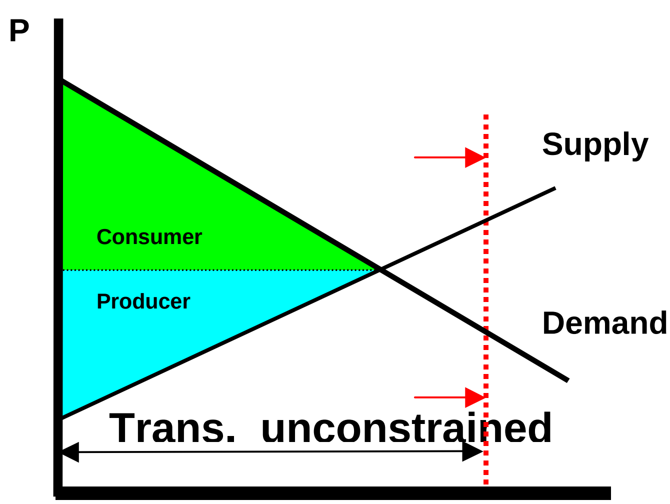
Note: These revenues totaled approximately $470 million/year when summed across all constrained paths and all hours of the 2008 Base Case scenario.

However, in an efficient and competitive transmission rights market, both Tprice and congestion revenue decrease as transmission capacity is added *(i.e., shifting the dotted red constraint line to right).*

As a result, congestion rents that were going to the owners of transmission capacity rights are re-distributed to consumers and producers on both sides of the path.

This is <u>largely</u> a wealth transfer, not a real gain in societal benefits.

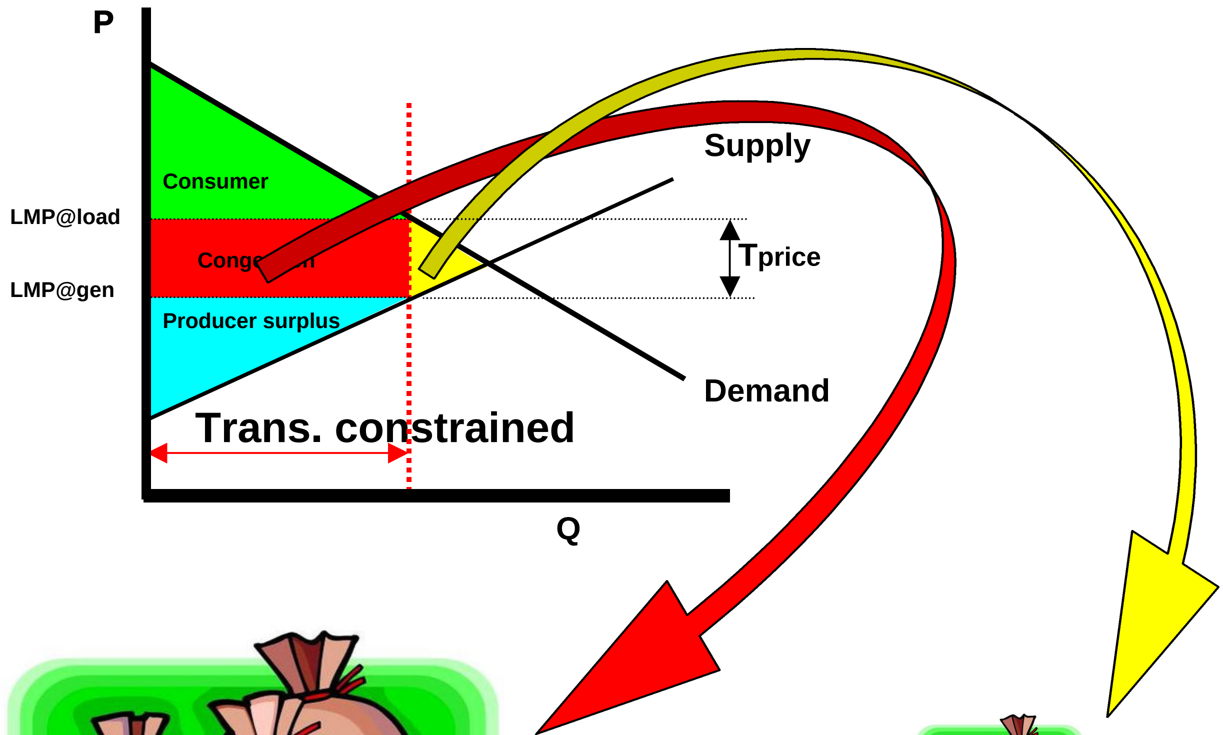




…The <u>real</u> societal benefit from adding transmission capacity come in the form of enhanced reliability, reduced market power, decreases in system capital and variable operating costs and changes in total demand.

The benefits associated with reliability, capital costs, market power and demand are not included in this analysis. However, the reduction in variable operating and maintenance costs, i.e., the VOM benefits, were estimated at approximately $110 million/year and are represented by the vanishing yellow triangle shown above.

A conceptual representation of the 2008 study results (cont)



$470 million/year

$110 million/year

… If all transactions using a constrained path pay Tprice, then the total amount of congestion revenue collected by owners of transmission rights *(red rectangular area)* can significantly exceed the total societal benefits *(yellow triangular area)* that stem from of building additional transmission capacity.

Hence, serious *equity issues* may be raised when the re-distribution of congestion rents among producers and consumers is taken into account.

The economic decision to build additional transmission capacity is not really based on the *amount* of congestion revenue collected. Congestion revenue only represents what could be made available for transmission expansion – not what should be spent.

If all of the congestion revenue were allocated to capital improvements, the transmission system would end up being over-built...

…If the reliability, capital, market power and consumption benefits associated with transmission expansion were included in our analysis, then the "yellow" area would represent a theoretical upper bound on what could be spent on new transmission capacity.

If expansion was free, we could afford to spend the entire amount. But it isn't, so expansion only makes sense while the following is true:

Tprice = Marginal Value Trans.
Capacity $\geq$ Marginal Cost Trans.
capacity

As can be seen in the first three diagrams, "Tprice", the marginal value of transmission capacity, decreases as additional transmission capacity is added to the system. Hence at a certain point, it's more economic to pay congestion rents than expand the system.

VI 2013 Simulation Results

The model was run for 28 cases in 2013:

1. Three runs for Average Water, Medium Gas (i.e. $3.23/mmbtu average wellhead price) with 2008 likely transmission scenario. One for the Gas Scenario additions; one for the Coal Scenario additions; and one for the Renewable Scenario additions.
2. Three runs for Average Water, Medium Gas, 2008 transmission with no constraints. One for the Gas Scenario additions; one for the Coal Scenario additions; and one for the Renewable Scenario additions.
3. Three runs for Average Water, Medium Gas with first cut at 2013 transmission additions. One for the Gas Scenario additions; one for the Coal Scenario additions; and one for the Renewable Scenario additions.
4. Three runs for Average Water, Medium Gas with second cut at 2013 Transmission additions. One for the Gas Scenario additions; one for the Coal Scenario additions; and one for the Renewable Scenario additions.
5. Twelve final runs for the following cases: 1). Low Water, High Gas ($5.65/mmbtu average wellhead price); 2). Average Water, High Gas; 3). Average Water, Medium Gas; and 4). High Water, Medium Gas. Each case was run for each of the following scenarios:
    - Gas Scenario
    - Coal Scenario
    - Renewable Scenario
6. Four runs for the 2008 generation and transmission assumptions but with the 2013 loads for the same cases as described in 5 constitute the base cases with which the cases in 5 are compared to estimate incremental costs and benefits of new transmission and generation infrastructure.

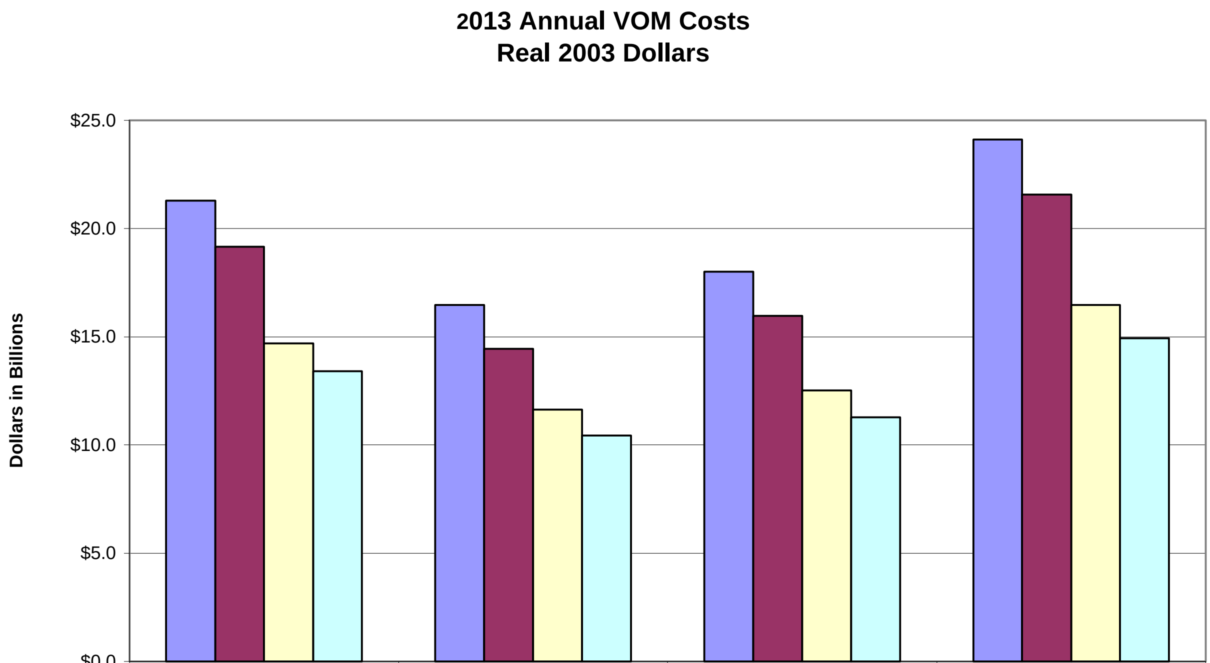
The first two groups of runs (cases in 1&2 above) were used to identify the degree and rough costs of transmission constraints in the three scenarios. Transmission additions were then proposed and tested in the next two groups (case in 3&4 above).

After final adjustments to the transmission plans were made, considering the results from the runs in case analyses in 3&4 above; the main block of runs were performed as described in 5&6. The estimated total VOM costs by scenario and sensitivity assumptions are illustrated in Figure VI-1. Figure VI-2 shows the resource mixes assumed for each of the scenarios. Table IV-2 summarizes the major transmission additions assumed for each of the scenarios.

<u>Variable O&M (VOM) Cost Analysis</u>

The total VOM costs are estimated at $13.4 to 21.3 billion for 2013 in the Gas Scenario, depending on water and gas assumptions. The Coal Scenario saves roughly $4 billion from the Gas Scenario; total VOM is estimated at $10.4 to 16.5 Billion, depending on gas and water assumptions. The Renewable Scenario saves roughly $3 billion from the

Gas Scenario, but has VOM costs roughly $1 billion more than the Coal Scenario; total VOM is estimated at $11.3 to 18.0 Billion, depending on gas and water assumptions.



	2013 Gas	2013 Coal	2013 Renewable	w/ 08 Gen & Trans
LW-HG	$21.3	$16.5	$18.0	$24.1
AW-HG	$19.2	$14.4	$16.0	$21.6
AW-MG	$14.7	$11.6	$12.5	$16.5
HW-MG	$13.4	$10.4	$11.3	$14.9

Figure VI-1

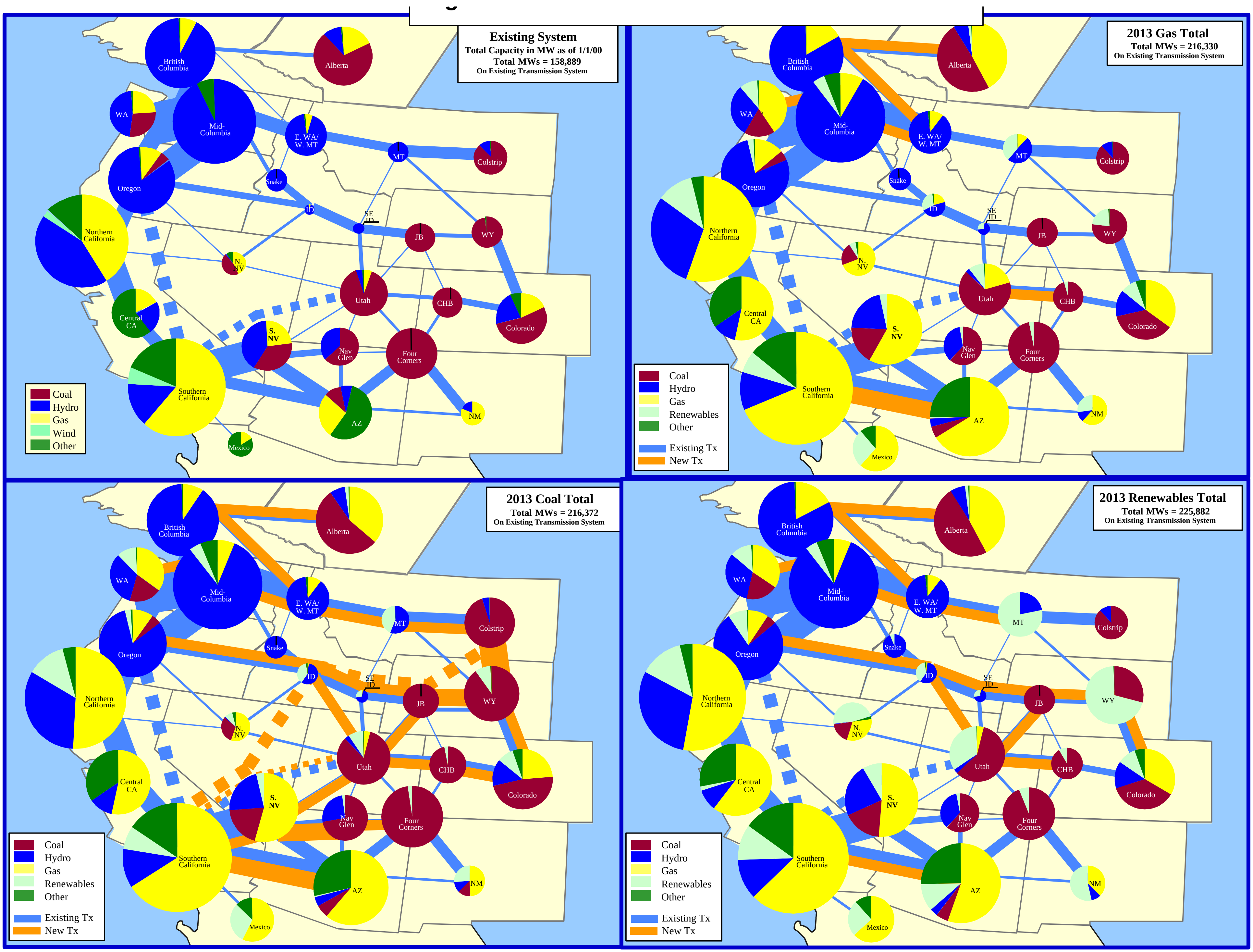
The total economics of these cases depend on a combination of VOM costs as well as the fixed costs for maintenance and capital payments for transmission, generation, and fuel delivery. There may also be benefits due to increased reliability of the generation and transmission system, environmental externalities and considerations of fuel diversity. The final four runs were made with the 2008 generation and transmission assumptions and the 2013 loads. These studies allow an estimate of the cost of serving loads (assuming unlimited load shedding was available for $150/MWh) with no additional capital from the 2008 base case. The total VOM for these cases ranges between 14.9 to 24.1 billion, depending on water and fuel assumptions. This puts the approximate total VOM savings for building the Gas scenario at around $2 billion, while the Coal scenario would save about $6 billion and the Renewable Scenario $5 billion. A cursory comparison of costs and benefits is found on Table VI-1.

Table VI-1
Summary of 2013 Study Results
Benefits, Capital Costs, CO2 Emissions & Simple Payback

BENEFITS & SIMPLE PAYBACK						
Analysis Description	**VOM BENEFITS** ($ M/yr)			**SIMPLE PAYBACK** (years)		
	Gas	**Coal**	**Renewable**	**Gas**	**Coal**	**Renewable**
avg water, high gas	2,400	7,100	5,600	8.4	6.6	7.8
avg water, med gas	1,800	4,800	3,900	11.4	9.8	11.0
low water, high gas	2,800	7,600	6,100	7.1	6.2	7.1
high water, med gas	1,500	4,500	3,700	13.1	10.5	11.9
CAPITAL COSTS ($M)						
	Gas	**Coal**	**Renewable**			
Transmission	2,600	16,700	6,700			
Generation	17,000	30,500	36,800			
CO2 EMISSIONS						
	Gas	**Coal**	**Renewable**			
Tons/year - millions	439	522	406			
% of 1995 actual	136	161	125			

Table VI-2
Summary of Major Transmission Additions
2013 Gas, Coal and Renewable Scenarios

Line Addition (500 kV AC unless noted)	**Length**	**Path Number**	**Geographic Description**	**Gas Scenario**	**Coal Scenario**	**Renewable Scenario**
Langdon-Cranbrook-Selkirk-Bell	420	1,3	Alberta to BC to Northwest	**X**	**X**	**X**
Harquala-Devers	225	46	Arizona to California	**X**	**X**	**X**
Hassyamp-North Gila-Imperial Valley-Miguel	260	49	Arizona to California	**X**	**X**	**X**
Sycamore-Ramona-Imperial Valley	120	42	Into San Diego	**X**	**X**	**X**
Chief Joe-Monroe	120	4	Into Puget Sound	**X**	**X**	**X**
Grand Junction-Emery 345 kV line	180	30	Colorado to Utah	**X**	**X**	**X**
Garrison-Hot Springs-Bell-Ashe	425	6	Western Montana to Washington		**X**	**X**
Midpoint-Melba-Grizzly	370	14	Idaho to Oregon		**X**	**X**
Melba-Caldwell-Locust-Boise Bench 230 kV line	100	14	Idaho to Oregon		**X**	**X**
Bridger-Ben Lomond-Midpoint	470	17, 19, 20	Wyoming to Utah to Idaho		**X**	**X**
Bridger-Midpoint	320	17, 19	Wyoming to Idaho		**X**	**X**
Green Valley-Stegall-Bridger	450	New	Through Wyoming			**X**
Colstrip-Broadview-Garrison	335	8	Through Montana		**X**	
Crystal-Mira Loma	260	46	Arizona to California		**X**	
Colstrip-Wyodak (3 lines)	390	38	Montana to Wyoming		**X**	
Wyodak-Bridger	290	37	Through Wyoming		**X**	
Wyodak-Laramie	135	New	Through Wyoming		**X**	
Emery-Mona-Crystal	340	31, 35, 78, 79	Utah to Nevada		**X**	
Wyodak-Los Angesel 500 kV DC	1375	Several	Wyoming to California		**X**	
Shiprock-Moenkopi-Market Place	542	22, 23, others	Arizona to Nevada		**X**	
Laramie River-Green Valley-Grand Junction- Craig	540	36, 39, 40	Wyoming to Colorado		**X**	
Ben Lomond-Mona	108	New	Through Utah		**X**	
Hassyamp-North Gila-Imperial Valley-Miguel	280	46, 49	Arizona to California		**x**	
Total Transmission Line Miles				**1325**	**7600**	**3360**


Existing System
Total Capacity in MW as of 1/1/00
Total MWs = 158,889
On Existing Transmission System
Coal
Hydro
Gas
Wind
Other
British Columbia
Alberta
WA
Mid-Columbia
E. WA/ W. MT
MT
Colstrip
Oregon
Snake
ID
SE ID
JB
WY
Northern California
N. NV
Utah
CHB
Colorado
Central CA
S. NV
Nav Glen
Four Corners
Southern California
AZ
NM
Mexico
2013 Gas Total
Total MWs = 216,330
On Existing Transmission System
Coal
Hydro
Gas
Renewables
Other
Existing Tx
New Tx
2013 Coal Total
Total MWs = 216,372
On Existing Transmission System
Coal
Hydro
Gas
Renewables
Other
Existing Tx
New Tx
2013 Renewables Total
Total MWs = 225,882
On Existing Transmission System
Coal
Hydro
Gas
Renewables
Other
Existing Tx
New Tx

Shadow Price Analysis

Transmission line shadow prices were calculated to identify the annual production cost savings that would be obtained by increasing the line or path capacity by one megawatt in both directions. Appendix D2 contains a list of facility shadow prices for each scenario.

Load Duration Curves

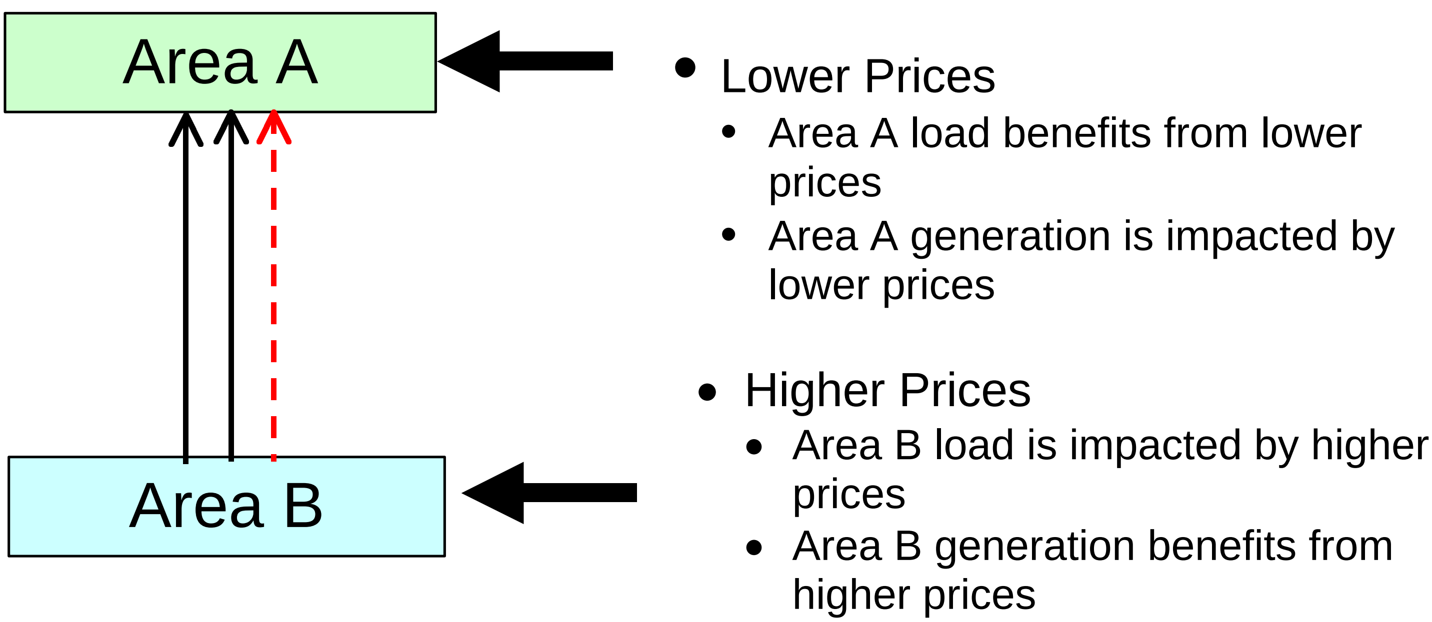
Load duration curves were computed for the paths with highest shadow prices with the path flows capped at the path capacity rating. These curves give an indication of the percent of time a path is operated at or near its rated capability. Information from these curves, together with shadow price information, produces a more complete picture of the extent and value of clearing congestion. These curves are included in Appendix D2.

LMP Analysis

Locational Marginal Prices were calculated for selected buses for each scenario and sensitivity. These are tabulated in Appendix D2. The LMP values represent the average LMP over the year. Maximum and minimum LMP values are also presented.

Figure VI-3 shows that the changes in LMPs for loads and generators represents a shifting of benefits between these two groups, which helps to identify the beneficiaries of new transmission projects. However, with the addition of new transmission facilities, there generally is an overall reduction in the production cost of generation, which is considered a key benefit. For further discussion of these concepts, refer to SIDEBAR 1 under Section V.

Figure VI-3: Valuing Access to Lower Cost Power



VII Description of SSG-WI Planning Function and its Interactions Within the Western Interconnection:

SSG-WI Planning Function

The design of a transmission planning function that is proactive and interconnection-wide by the SSG-WI PWG represents the implementation of another important next step identified in the WGA report along the continuum toward construction of critical transmission infrastructure. (See Figure E-4). The SSG-WI planning function is open to all market participants, Western states and provinces, and other stakeholders within the Western Interconnection. The planning function will identify transmission congestion issues that impact the marketing of energy between RTOs or sub-regions, including the study of congested paths within a region that may impact on the ability to market between sub-regions. The study of transmission congestion within an RTO that does not impact other sub-regions remains the responsibility of the individual RTOs or local/sub-regional entities. However, RTOs or other entities may request the SSG-WI's Planning Work Group's assistance in evaluating, or developing, specific projects.

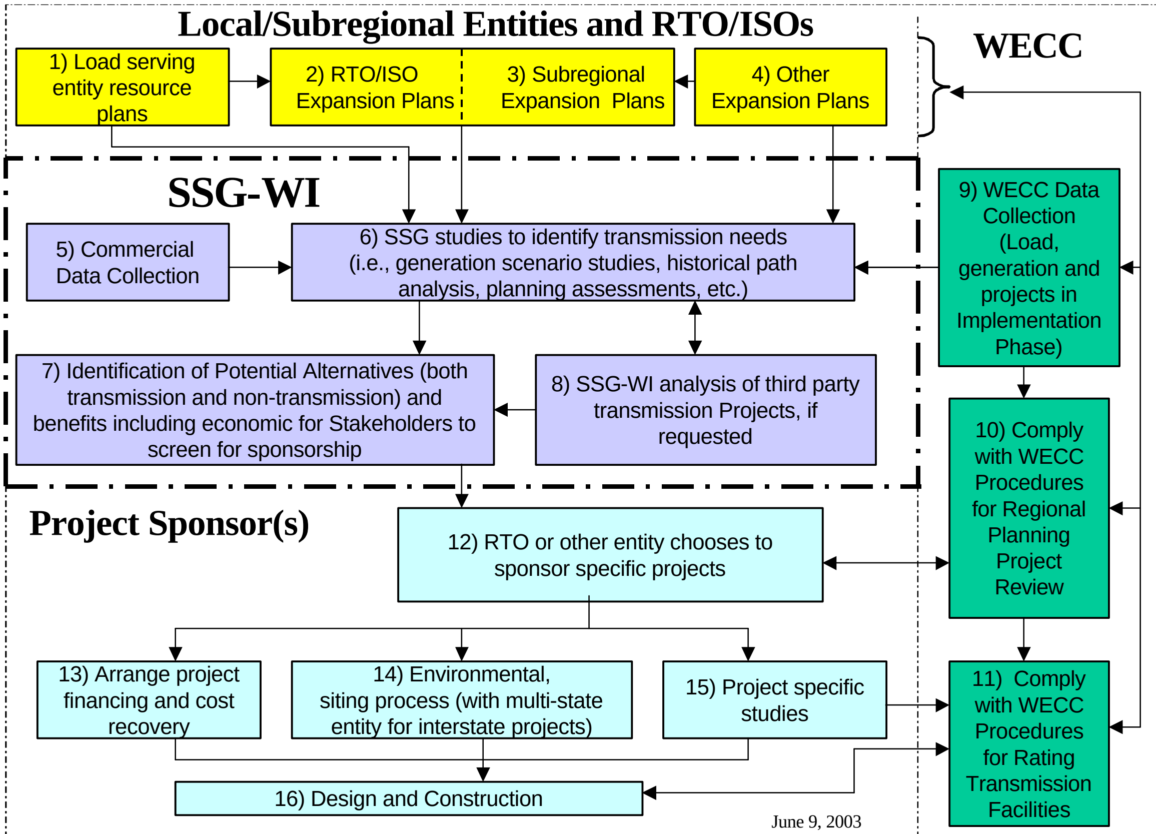
Regional transmission planning performed by the RTOs/ISOs, sub-regions and others within the West each make up an important part of the overall transmission planning process for the West. SSG-WI provides for a seamless transmission planning function throughout the interconnection enabling the coordination of individual company plans, sub-regional transmission plans including those to be developed by RTOs, and interconnection-wide transmission plans. See Appendix F for descriptions of the Sub-regional planning processes. The SSG-WI planning function provides information for Load Serving Entities (LSEs), other market participants and state/provincial policy makers to make informed decisions about the transmission implications of possible resource scenarios. The study time horizon is five years and beyond.

Planning by SSG-WI comports with the regional planning guidelines contained in WECC's bylaws. SSG-WI's planning activities are linked to transmission planning done by LSEs, sub-regional planning, and future RTO planning. Figure VII-1 illustrates how SSG-WI planning is integrated with other planning activities in the Western Interconnection.

A complete description of the SSG-WI Planning Function can be found on SSG-WI's website: http://www.ssg-wi.com/documents/.

Figure VII-1

SSG-WI Planning Function's Interactions within the Western Interconnection



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Sub-regional Planning

Prior to the formation of RTOs in the West, Subregional Planning Groups (SPGs), working in cooperation with the SSG-WI PWG, are starting to play a significant role in the planning of the Western Interconnection transmission system. The SPGs are starting to perform detailed evaluations of identified transmission needs by the SSG-WI PWG. The SPGs include such stakeholders as utilities, regulators, state energy offices, transmission providers, generators and other interested parties in order to find solutions to local transmission needs.

SSG-WI and the SPGs are developing a cooperative, supportive and complementary working relationship. Both SSG-WI and the SPGs are working together to develop models and databases for production costing planning studies. SSG-WI focuses on interconnection-wide needs. Results of SSG-WI studies feed into the evaluations by the SPGs, which include further economic analyses and detailed planning studies involving local transmission providers and stakeholders. Results of SPG studies will then feed into SSG-WI for evaluation of potential interconnection-wide benefits to entities beyond the local level.

Several SPGs have already formed or are in the formative stages. The following paragraphs provide brief summaries of these SPGs. See Appendix F for a more complete description of the SPGs.

Central Arizona Transmission System (CATS)

The CATS SPG is focusing on development of the transmission system between the Phoenix and Tucson areas in Arizona. It is addressing transmission concerns related to load growth in this area and proposed generation additions in this area of approximately 10,000 MW. Participants include Arizona Public Service, Salt River Project, Tucson Electric Company, Southwest Transmission Cooperative, Citizens Communications Company, WAPA, and the Arizona Corporation Commission staff. The project was opened up to all stakeholders, thus many more participants have become involved.

Today, the study area encompasses an area bounded by the Phoenix Metropolitan area to the north, the Tucson Metropolitan area to the south, the Palo Verde Generating Station to the west and the Arizona/New Mexico border to the east. An initial meeting was held in March 2000. The CATS Phase I Study was completed and report published in July 2001. The first CATS Phase II meeting was held in August 2001.Phase II analyzed the combining of several Phase I alternatives, and integrating other proposed transmission projects in Arizona that were not included in CATS Phase I.

Web Site for the CATS Sub-regional Planning Group is http://www.azpower.org/.

Southwest Transmission Expansion Plan (STEP)

The goal of STEP is “To provide a forum where all interested parties are encouraged to participate in the planning, coordination, and implementation of a robust transmission system between the Arizona, Nevada, Mexico, and southern California areas that is capable of supporting a competitive efficient and seamless west-side wholesale electricity market while meeting established reliability standards. The wide participation envisioned in this process is intended to result in a plan that meets a variety of needs and has a broad basis of support.

STEP is an ad-hoc voluntary organization whose membership is open to all interested stakeholders. STEP’s focus is on economically driven expansion projects that support the development of seamless west-wide markets. STEP will work with project sponsors to help assess the benefits of their independent transmission proposals.

STEP will develop a biennial planning process that produces a long-term bulk transmission expansion plan (10 years or more). It will identify current and future transmission congestion that is an impediment to the efficient operation of the western market. STEP will develop, through a collaborative process, strategic transmission options and specific alternative plans for reinforcing the transmission system and for reducing or eliminating g congestion. This information will e provided to the market place. It will rely as much as possible on the technical studies conducted by project sponsors and studies conducted in other forums. STEP will perform technical study work that is not duplicative of work done by others.

Additional information on STEP is available at the web site http://www1.caiso.com/docs/2002/11/04/2002110417450022131.html.

SIDEBAR 2 describes an early success story in the evolving WI transmission expansion planning process.

Rocky Mountain Sub-regional Planning Group

The Rocky Mountain SPG is an effort initiated by the Governors of the states of Wyoming and Utah. The Goal is: "To identify in an open and public process, the most critical electric transmission and generation project needs in the Rocky Mountain sub-region, and with broad stakeholder involvement provide a framework for regional collaboration to improve the Western Interconnection with technical, financial and environmentally viable projects identified for developmental consideration."

Electric transmission in the Rocky Mountain region is constrained in part and as a result, the region's vast wind, natural gas and coal resources are underutilized. RTOs are years from effective operation and there is no current collaborative Rocky Mountain planning effort to consider transmission expansion from a holistic perspective.

Participants in this process include Western Interconnection electric utilities, Independent Power Producers (IPPs), rural electric generation and transmission cooperatives, municipalities, federal power, transmission and marketing agencies, project developers, entrepreneurs, power brokers, state and federal regulators, state energy office representatives and anyone interested in regional electric generation and transmission planning.

Additional information on the Rocky Mountain Subregional Planning Group may be found at their web site http://psc.state.wy.us/htdocs/subregional/home.htm.

Northwest Transmission Assessment Committee (NTAC)

The Northwest utilities and stakeholders are currently organizing an SPG in the Northwest under the Northwest Power Pool. An initial organizing meeting was held August 6, 2003 in Portland, Oregon. The Scope of the group's activities is currently under development. It is planned to focus the group on expansion of the Northwest transmission system, identifying congestion and potential solutions in order to meet the projected future needs of the wholesale electricity market in the Northwest.

Additional information on the Northwest Sub-regional Planning Group will be posted under the Northwest Power Pool's web site at http://www.nwpp.org.

SIDEBAR 2: Early Success Story of SSG-WI- STEP Coordination:

Southwest Transmission Expansion Plan (STEP) is a sub-regional planning group that was formed to address transmission concerns in the Arizona, southern Nevada, southern California, and northern Mexico area. As a result of a large amount of new generation developed in this area, it was apparent to many that the transmission grid would be inadequate to efficiently deliver that power to the major load areas. STEP was initiated in November of 2002 primarily to address this concern and is conducting both technical (powerflow and stability) and economic (production cost) studies. STEP works closely with Central Arizona Transmission Study (CATS - another sub-regional planning group) to evaluate transmission that cross the seam between Arizona and California.

For the economic studies, STEP has relied on the data that SSG-WI compiled and on the studies that SSG-WI produced. The SSG-WI studies for 2008 and 2013 provide an independent overview of areas where transmission may be needed and help focus STEP on areas of concern and on specific scenarios. These economic studies have confirmed the general opinion that transmission facilities in the area were inadequate to efficiently deliver the new generation to the load areas.

To develop transmission projects to mitigate inefficient congestion on the system, STEP developed a large number of potential transmission upgrade plans. In fact, STEP analyzed more than 25 different upgrade scenarios. Based upon the technical and economic studies, and a consensus building process, this large number of initial alternatives was narrowed down to less than four and STEP has begun implementing several of the initial steps that are common to all the remaining upgrade scenarios. These initial steps primarily involve upgrades to the series capacitors in several existing 500 kV lines. By early next year, STEP expects to have some of the larger system upgrades agreed upon and to initiate their implementation. All together, the total cost of the economic transmission additions being developed by STEP is expected to exceed one billion dollars. Even after this initial need is addressed by STEP, STEP intends to continue to be active as a sub-regional planning forum to help insure that the future transmission grid in this area will be developed in a coordinated and efficient manner.

The work that is completed by STEP and other sub-regional planning groups also assists SSG-WI in their efforts to develop an efficient interconnection-wide grid. As STEP and other sub-regional groups makes improvements in the model or develops transmission projects, this information is provided to SSG-WI. SSG-WI which can then use this information to improve the interconnection-wide modeling.

VIII. Findings, Accomplishments and Next Steps

Findings

A comparison of the average hydro and medium gas price condition in the 2008 study with a similar study of an unconstrained transmission system (see Figure V-I in the report) indicates that there is significant stranding of low-cost generation in Canada and in the Desert Southwest. Approximately 1300 miles of new 345 and 500 kV line would be required to completely alleviate this identified congestion, which could result in an annual savings in the production cost of generation, or Variable Operating and Maintenance (VOM) costs, totaling at least $110 million. One of the Sub-regional Planning Groups, the Southwest Transmission Expansion, or STEP Group, is already undertaking a more detailed investigation of upgrading existing lines and adding approximately 225 miles of new transmission line in the California-Arizona corridor. STEP estimates the benefit of this proposed project to be on the order of $60 million per year.

The study did not explicitly model the impact of measures to reduce demand. However, the study results do provide insights into the effect of load reduction on the need for transmission. In addition, the study shows that the need for new transmission is more sensitive to the price of natural gas than to hydro conditions, primarily because new generation added in the WI between 1998 and 2008 is predominantly natural gas-fired with over 25% of generation resources in 2008 fueled by natural gas.

Figure E-1 shows the results of the 2013 scenarios in terms of the costs, benefits, and simple payback periods associated with constructing new transmission and generation infrastructure compared to the benchmark case of no new infrastructure. As shown, a cursory evaluation of the capital costs of transmission and generation infrastructure was performed. The benefits in terms of production cost savings (VOM cost savings) are derived from the model results. Such costs as the cost of additional gas pipeline infrastructure or the costs associated with potential carbon emission regulation have not been evaluated. Benefits stemming from reliability improvements, improved market competition and increased ancillary services have also not been quantified. Although the study results should not be construed to mean that a particular scenario is cost-effective to construct because there is a need for more detailed analyses, the results do show simple payback periods of 6 to 13 years for the range of scenarios and sensitivities studied. Expected generation/transmission scenarios for the various WI sub-regions merit further evaluation, including the consideration of non-transmission alternatives such as demand reduction measures.

The new transmission infrastructure assumed to be in place by 2013 under each of the scenarios to facilitate the efficient use of generation to meet load is graphically shown in Figure E-2. The underlying system represents that which would be operational by 2008.

Accomplishments in Meeting Study Objectives

This report is an important step in meeting SSG-WI's transmission planning objectives and makes a valuable contribution to reestablishing the linkage between generation development and transmission construction.

STUDY OBJECTIVE 1: IDENTIFY TRANSMISSION INFRASTRUCTURE TO FACILITATE MARKETS:

In furtherance of SSG-WI's first objective, the studies identify:

- Areas in the Western Interconnection that are or may be congested in the near future (2008); and

- Transmission facilities necessary to minimize production costs for three bookend generation scenarios.

Given the load and resource assumptions, these expansions of the transmission system are cost-effective. Further analysis is required before specific projects can be selected for construction.

Solutions are being investigated in sub-regional planning forums. Sub-regional transmission assessments can define specific projects, identify the beneficiaries of such projects, and create the coalition of interests necessary for transmission infrastructure implementation. An iterative transmission planning process has been defined. The iterative process includes annual studies by the SSG-WI planning function and detailed investigations by the Sub-regional Planning Groups and the RTOs (once they are formed). All of these activities will be coordinated with state entities and local utilities performing integrated resource planning. (See Figure E-3, for a graphical depiction of this process.)

The SSG-WI planning effort is currently based on the voluntary support of interested stakeholders. Given the diverse makeup of the Western Interconnection, a large number of individual transmission owners and other interested parties are involved in this effort. This approach to planning transmission can be successful; however, implementing the projects that are planned can be difficult because of the many interests involved. The development of RTO's is expected to significantly mitigate this barrier, as the RTO's will have processes that not only facilitate planning, but also fund and construct new transmission.

STUDY OBJECTIVE 2: IMPACT OF ENERGY POLICY ON TRANSMISSION:

In furtherance of SSG-WI's second objective, the PWG:

- Finds that planning and implementation of transmission and generation infrastructure are difficult to coordinate because transmission infrastructure generally takes significantly longer to develop than generation infrastructure.

- Identifies transmission expansion that would relieve congestion for the coal, gas and renewable generation scenarios evaluated. (See Figure E-2)

- Finds that the transmission needed with the Renewable Scenario will support the amount of renewable energy generation necessary to satisfy the Renewable Portfolio Standards (RPS) that four states within the Western Interconnection have enacted. [4] Since the renewable generation levels in the Renewable Scenario exceed the RPS requirements, additional studies may be required to identify the minimum transmission required by the state RPS levels.

- Identifies transmission expansion that might lower electricity costs to consumers based on the preliminary economic analyses performed.

Energy policy-makers are currently faced with a number of issues and uncertainties that are tied directly or indirectly to transmission infrastructure development. National energy legislation may be forthcoming soon that addresses such issues as mandatory reliability standards, regional transmission organizations and electricity market designs.

In addition to transmission infrastructure adequacy, energy policy-makers are concerned with resource adequacy and diversity. A number of states within the Western Interconnection have enacted energy legislation that includes RPS, energy efficiency, environmental and other requirements. Following the Western Energy crisis of 2001, a number of states and regions are exploring whether to implement resource adequacy requirements. In addition, state regulators and load serving entities (LSEs) have renewed their efforts to perform integrated resource planning evaluations.

The scenario analyses performed by SSG-WI can help inform state policy-makers and regulators of the cost of transmission associated with alternative generation sources. This is valuable input into integrated resource planning activities, resource adequacy assessments and other evaluations being performed to address the issues identified above. These analyses are particularly valuable in providing insights into transmission additions that can support resource diversity and thus improve reliability. Conversely, the transmission infrastructure development process, graphically depicted in Figure E-3, depends on input from states, LSEs and developers. Transmission planning must be integrated with utility and independent developer plans in sub-regional studies in order to arrive at solutions for transmission and generation infrastructure that fully support the goals of energy policy-makers. Finally, detailed analyses of the impact of transmission additions on system reliability need to be conducted.

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[4] It is unclear whether the RPS requirements in the various states apply only to new, or also include existing renewable resources. The SSG-WI studies assumed that only new renewable resources count toward satisfying RPS requirements.

OBJECTIVE 3: IDENTIFY TRANSMISSION NEEDED TO DELIVER RESOURCES TO MARKET:

In furtherance of SSG-WI's third objective, the PWG finds:

- Gas-fired resources require significantly less new transmission since these resources are generally located near load centers.

- Significant transmission additions are required to transmit remote coal and renewable resources identified in the study to load centers. The results of this initial screening are promising in terms of identifying potentially cost-effective additions for the assumed resources scenarios.

- The transmission facilities identified for all of the scenarios may also provide reliability benefits for the WI power system.

- Certain transmission facilities were found to be needed in all three resource scenarios. Since the need for these facilities is less sensitive to resource assumptions, the sub-regional planning groups may want to focus first on these facilities as possible economic additions to the system.

As part of this initial study effort, a WI production-costing database has been developed. SSG-WI intends that this database be made available for use by the Sub-regional Planning Groups and others interested in joint database development. A beneficial and effective relationship has been established between the SSG-WI PWG and the western Sub-regional Planning Groups. These consensus-based efforts should be supported and encouraged to continue. These efforts will be expanded to include RTOs, once these are formed.

Next Steps

The following steps are proposed to advance transmission development in the Western Interconnection:

- Federal, State and local policy-makers need to address and resolve institutional and financial barriers[5] to the construction of needed transmission infrastructure. These issues include transmission line siting, cost allocation and cost recovery. These issues need to be resolved to encourage investment in transmission infrastructure and demand efficiency measures at loads.

- The Sub-regional Planning Groups should perform more in-depth transmission expansion planning studies for those facilities within their sub-regions identified in this SSG-WI study, based upon expected generation additions and load forecasts

[5] Barriers exist that impede not only the construction of transmission lines, but also that impede demand-side technologies, including strategically sited generation, to delay or obviate the need for new transmission lines.

(e.g. coordinated with utility integrated resource plans that are approved by state public utility commissions);

- SSG-WI should perform annual reviews of the utilization of the existing transmission system, potential future needs, and expansion issues, including those issues associated with differences in transmission and generation construction lead times. SSG-WI should coordinate its future study program with the Sub-regional Planning Groups. SSG-WI should initiate long-term planning efforts and identify appropriate cost and benefit indicators for future analysis, including fuel price volatility, fuel availability, environmental impact, ancillary service impacts, construction lead times, losses, reliability improvement and impacts on market competition.

- Development and funding of model and economic methodology improvements and forums to improve transmission planning methodologies need to be investigated and pursued. For example, study methodologies (particularly benefit calculations) need to be fine-tuned and improvements are needed to more accurately model hydro and wind resources as well as market behavior. A process for continuing the development of a common, public and consistent database needs to be finalized.

- Federal, state and local policy-makers will need to decide whether to finance and permit transmission expansions to facilitate generation resource diversity, including meeting renewable energy goals in RPS's.

- As Sub-regional Planning Groups perform detailed studies to identify beneficiaries and as incentive pricing and cost recovery issues are addressed and resolved, coalitions of interested parties will need to come together to plan, finance and construct critical transmission infrastructure. The development of RTOs will likely be critical to making mechanisms available to fund and construct new transmission infrastructure.